OPERATING STRATEGIES TO PRESERVE THE ADEQUACY OF POWER SYSTEMS CIRCUIT BREAKERS

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OPERATING STRATEGIES TO PRESERVE THE ADEQUACY OF POWER SYSTEMS CIRCUIT BREAKERS

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To my late Father, Đàm Quang Linh:

Wherever you are resting, be assured that the work is now complete.

To my mother, Nghĩa, to my paternal and maternal grandmothers,

and to my brothers Đức and Vân.

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SUMMARY

The objective of the proposed research is to quantify the limits of overstressed and aging circuit breakers in terms of probability of failure and to provide guidelines to determine network reconfigurations, generator commitment, and economic dispatch strategies that account for these limits. These temporary power system operating strategies address circuit breaker adequacy issues, and overstressed breakers can be operated longer and more reliably until they are replaced with adequate equipment.

The expansion of electric networks with new power sources (nuclear plants, distributed generation) results in increased short-circuit (fault) currents levels. A number of circuit breakers do not have sufficient ratings to interrupt these increased faults currents. These breakers are said to be overstressed (underrated, inadequate). Because of their insufficient ratings, overstressed breakers are subject to increased failure probabilities. Extensive common-mode outages caused by circuit breaker failures reduce the reliability of power systems. To avoid outages and system unreliability, overstressed breakers must eventually be replaced.

The replacement of overstressed breakers cannot be completed in a short time because of budgetary limits, capital improvement schedules, and manufacturer-imposed constraints. Meanwhile, to preserve the ability of old and overstressed breakers to safely interrupt faults, short-circuit currents must be kept within the limits imposed by the ratings and the age of these breakers, using the substation reconfiguration and generator commitment strategies described in this study.

The immediate benefit of the above-mentioned operating strategies is a reduction of the failure probability of overstressed breakers obtained by avoiding the interruption of currents in excess of breaker ratings. Other benefits include (i) more reliable

network operation, (ii) restored operating margins with respect to existing equipment, and (iii) prioritized equipment upgrades that enable improvements in power systems planning.

The proposed work is illustrated using a three-phase, breaker-oriented 24-substation test system that extends the existing IEEE Reliability Test System.

CHAPTER I

INTRODUCTION AND PROBLEM STATEMENT

1.1 Human Vulnerability to Power Outages

Electricity supports the core needs of modern civilization. Lighting, health equipment, and information technology are just a few examples of electricity-powered systems that the vast majority of people rely on. The demand for a reliable energy supply has significantly increased with population growth, business expansions, and the fact that, in developed countries, the availability of electricity is taken for granted [1]. With such a dependency on electricity (and with the tendency to forget how it is generated and transmitted), any disruption in the power supply can have tremendous consequences, such as lost business revenues, paralyzed cities, or the interruption of critical and vital processes. The North-American blackout of August 2003 and outages across Europe during subsequent months reminded the world of its vulnerability to power outages. Even if companies and government agencies have prepared themselves for emergencies related to power outages [2, 3], the cost of an outage to one of the largest businesses may exceed millions of dollars per hour of downtime [4].

1.2 Power Systems Equipment Reliability Concerns

One very common cause of power interruptions originates from malfunctioning protective equipment that fails to interrupt and isolate faults. These failures significantly contribute to system unreliability. Considering recent events and trends in power systems operation, there are two causes that may lead to an increased number of system failures: equipment adequacy and equipment aging.

1.2.1 Generation Capacity Growth, Increased Fault Currents, and Circuit Breaker Adequacy

A leading cause of increased system failures is the operation of equipment beyond its design limits. Lines and switchgear are designed to carry or interrupt given currents that are determined by the expected power transfers at the time of construction.

As a result of population growth and technological progress, the demand and generation of electric power have dramatically increased between the last third of the 20^{th} century and the first decade of the 21^{th} century. On one hand, load currents and short-circuit currents have increased following this trend; on the other hand, many circuit breakers currently in service were installed in the late 1960s and were not upgraded to support these increased short-circuit (or fault) currents.

Although large coal and nuclear power plants contribute to most of the generation capacity, distributed generation is increasingly contributing to the expansion of power grids worldwide. Distributed generation includes renewable energy sources, cogeneration plants, and other independently-owned, small-scale generators that produce electricity using energy sources available locally. Distributed generation is advocated for its benefits in terms of reduced transmission congestion, system voltage stability, energy efficiency, and improved pollution levels [5, 6]. Unfortunately, the expansion of generation capacity has caused electric networks to be operated beyond their design transmission capacity. Moreover, distributed generation has become a leading cause of locally increased fault current levels [7, 8]. Increased fault currents pose a problem with circuit breaker ratings and unforeseen increases in the ground potential during short circuits. The resulting step-and-touch voltages may exceed safe levels for humans and other animals.

Overall, the expansion of power grids in developed countries has unintentionally brought electric utilities and large industrial consumers to a situation where circuit breakers may become underrated. Under certain fault conditions, the current exceeds the rating or interrupting capability of some breakers. This situation is referred to as circuit breaker inadequacy (Table 1).

Table 1: Synthetic example of the circuit breaker adequacy issue.

	Year y (Initial Condition)	Year $y + 20$
Highest fault current	25 kA	45 kA
Breaker rating	40 kA, new condition	40 kA less wear and tear
Is rating adequate?	Yes	No

The problem of circuit breaker inadequacy is not recent and occurs in transmission and distribution systems of various voltage levels [9, 10]. Although it is possible to retrofit certain breakers to increase their interrupting capability [11], the complexity and limited benefits of retrofitting modern equipment may justify replacing the equipment in the long term.

Circuit breakers are rated to interrupt fault currents up to a certain magnitude. Just as overloading a motor shortens its life, attempting to interrupt faults with a breaker not sufficiently rated increases its probability of failure. Circuit breaker failures may cause undesired, widespread outages as a result of the operation of backup protection schemes.

1.2.2 Reliability Issues with Aging Equipment

In developed (North-American and European) countries, the other leading cause of increased grid failures is the age of an infrastructure that was built decades ago for the most part. Circuit breakers are an integral part of this infrastructure. The age and weaknesses of such power systems are apparent, especially when it comes to powering sophisticated equipment that requires highly reliable supplies. The May 2006 issue of *IEEE Power & Energy Magazine* was titled "The Graying Power System" and was entirely devoted to the state and aging problems of electric grids.

Although investments tend to be cyclic, no massive improvements to the U.S. power systems infrastructure have been made since the late 1960s [12]. As a result, the vast majority of the grid equipment is now 40 years old or more. Experts note that such a remarkably long service age comes from the robust construction of the equipment itself [13]. But ultimately, old equipment wears out. With failure rates that abruptly increase with age, old equipment contributes to system unreliability.

The concern for utilities is not the aging of a single device, but the large amount of equipment simultaneously reaching an age that is synonymous with high failure rates (Figure 1). This phenomenon is known as the “escalation” of component failure rates. Utilities use this terminology to anticipate the potentially overwhelming costs to maintain and to replace old equipment [14, 15].

Circuit breakers are no exception to this observation of aging power systems in need for overdue upgrades. The replacement of circuit breakers in a single substation already costs millions of dollars. Considering the important number of substations in major grids, budget-related delays in equipment maintenance and upgrades and the lack of manpower to complete these upgrades adversely affect the reliability of power systems [16].

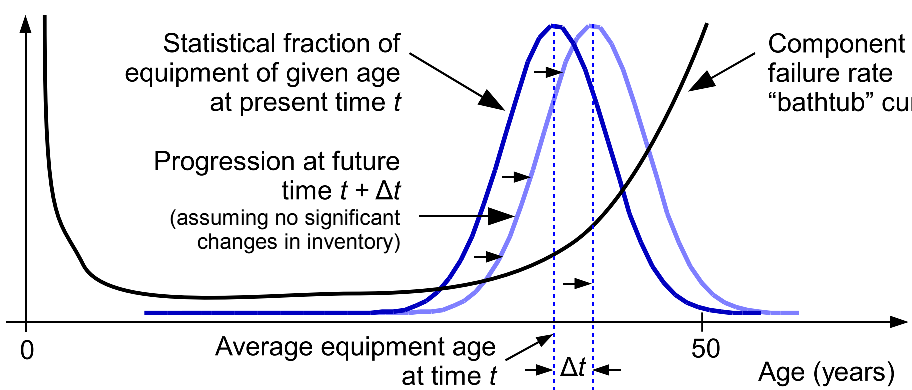


Figure 1: Illustration of the escalation of component failure rates.

The combination of equipment aging and equipment operation beyond its rated current significantly increases the chances of system failures. Safety and operational margins are reduced at the same time. A better understanding of the process causing fault currents to increase and leading to breaker adequacy issues, in conjunction with the existing knowledge of phenomena associated with equipment aging, can help prevent breaker failures and improve the reliability of power systems.

1.2.3 Causes for Grid Improvement Latency

Long before the August 2003 blackout, former U.S. Secretary of Energy Bill Richardson had warned U.S. political leaders of the urgent need to address the deteriorating state of the U.S. infrastructure:

> We are a major superpower with a third-world electrical grid [...] Our grid is antiquated. It needs serious modernization [12, 17, 18].

Traditional utility culture and planning processes have overlooked the issue of equipment massively reaching an advanced service age [13]. Another reason for the latency of grid improvements is the inability to reengineer certain obsolete system layouts that would otherwise provide additional operating flexibility [19]. As a result, many utilities have either operated parts of their system above their design limits or let their infrastructures decline by delaying capital replacements until the equipment failed. The latter practice is known as the "run-to-failure" approach [20].

Because of the aging failure rate escalation, utilities face overwhelming and urgent equipment upgrades that might not be possible with the resources they currently have.

The recent massive grid failures in North America highlighted the need to revise the maintenance and planning of power systems [6]. Perhaps as a result of lessons learned during these major outages, recent planning methodologies strive to make reliability studies an integral part of a process that ensures there is enough generation, transmission, and distribution capacity available to serve customer loads and face unexpected events [21]. In a word, equipment adequacy, including circuit breaker adequacy, is becoming part of new power system operating and planning practices.

1.3 Problem Statement and Thesis Outline

Circuit breakers are the most important component for the reliability of power grids. They isolate faulted areas of power systems to preserve normal operating conditions elsewhere. A failed circuit breaker means a protection barrier against faults lost and a reduction of system reliability. Therefore, avoiding circuit breaker failures is critical to preventing undesired extended outages.

Because short-circuit currents can heavily damage electrical equipment and produce dangerous increases in ground potential, faults must be quickly cleared without compromising the proper operation of the rest of the system. The oldest and most overdutied switchgear cannot interrrupt increased fault current levels without a high probability of failure. On one hand, it takes time before old and underrated breakers are replaced; on the other hand, the protection of the power system must perform reliably during that time. Regardless of when underrated breakers are replaced, underrated breakers pose new operating and protection constraints that eventually affect the operation of power systems.

The objective of the proposed research is to examine power system operating constraints and strategies to reduce the failure probability of overdutied circuit breakers and circumvent the problem of circuit breaker adequacy. The background idea is to keep fault currents within the interrupting capability of overstressed breakers whenever such breakers are required to operate. Specifically, the proposed work provides methodologies to

- build a circuit breaker reliability model that accounts for new implications of increased fault currents;
- determine and evaluate constraints on the operation of the network to reduce circuit breaker failure from these increased fault currents and improve the reliability of the system; and

- suggest possible remedial actions in an attempt to circumvent the issues of underrated circuit breakers.

This thesis is organized as follows: Two chapters are devoted to the fundamental role and limits of power system operation and protection to clarify the need to preserve circuit breaker adequacy. Specifically, the principles of power systems operation and fault analysis are reviewed in Chapter 2; the functionality and limitations of circuit breakers, protective relays, and other protection devices are described in Chapter 3. With the highlight of key operating and protection principles that are relevant to the need to preserve circuit breaker adequacy, existing strategies to circumvent circuit breaker inadequacy are reviewed in Chapter 4. Two other chapters are devoted to a reliability assessment of overstressed breakers and the implications of breaker operating limits on power systems. A methodology to assess the reliability and predict the lifetime of circuit breakers with regard to the growth of the power system is presented in Chapter 5. In Chapter 6, the implications of operating the system at a desired reliability level are investigated, and possible remedial actions to address circuit breaker inadequacy are suggested. The concepts presented throughout this study and directions for future applications are illustrated in Chapter 7 with numerical examples applied to a modified IEEE 24-bus test system.

CHAPTER II

POWER SYSTEMS OPERATION PRINCIPLES

2.1 Overview

To avoid circuit breaker failures, an understanding of the core principles of power systems operation and protection is required. The flow of currents and expected levels of fault currents through circuit breakers are dictated by the solutions of the power flow and economic dispatch problems. Thus, the reliability of circuit breakers is determined from the conditions of the power flow and economic dispatch problems.

The operational concepts of power systems are described in this chapter, and the focus is on power flow, economic dispatch, and basic fault analysis. As a sequel to fault analysis, protection devices and the fundamentals of power systems protection are the subject of Chapter 3.

2.2 Power Systems Models

Notations for electrical quantities are summarized in Table 2.

Table 2: Summary of phasor notations.

Notations	RMS[a]	Angle	Time-Domain Phasor	Steady-State Phasor[b]
Voltage	$V(t)$	$\delta(t)$	$\widetilde{V}(t) = V(t)\, e^{j(\omega t+\delta(t))}$	$\widetilde{V} = V\, e^{j\delta}$
Current	$I(t)$	$\theta(t)$	$\widetilde{I}(t) = I(t)\, e^{j(\omega t+\theta(t))}$	$\widetilde{I} = I\, e^{j\theta}$

[a]Root mean square.
[b]Independent of time.

2.2.1 Symmetrical Component Models

Balanced phase voltages $\widetilde{V}_A$, $\widetilde{V}_B$, and $\widetilde{V}_C$ and phase currents $\widetilde{I}_A$, $\widetilde{I}_B$, and $\widetilde{I}_C$ are of the same magnitude and 120° apart. The succession of phases (A, B, C) in this particular order is conventionally called the positive sequence:

$$\begin{bmatrix} \widetilde{V}_A \\ \widetilde{V}_B \\ \widetilde{V}_C \end{bmatrix} = \begin{bmatrix} 1 \\ a^2 \\ a \end{bmatrix} V\, e^{j\delta}, \qquad \begin{bmatrix} \widetilde{I}_A \\ \widetilde{I}_B \\ \widetilde{I}_C \end{bmatrix} = \begin{bmatrix} 1 \\ a^2 \\ a \end{bmatrix} I\, e^{j\theta}, \qquad \text{with } a = e^{j\frac{2\pi}{3}} = e^{j120^\circ}.$$

The (A, C, B) sequence is called the negative sequence. There is also a homopolar (zero) sequence that reflects currents in neutral conductors.

The Fortescue transformation converts per-phase circuit voltages into positive, negative, and zero sequence components $\widetilde{V}_1$, $\widetilde{V}_2$, and $\widetilde{V}_0$, and vice-versa [22]:

$$\begin{bmatrix} \widetilde{V}_1 \\ \widetilde{V}_2 \\ \widetilde{V}_0 \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & a & a^2 \\ 1 & a^2 & a \\ 1 & 1 & 1 \end{bmatrix} \begin{bmatrix} \widetilde{V}_A \\ \widetilde{V}_B \\ \widetilde{V}_C \end{bmatrix} \quad \text{and} \quad \begin{bmatrix} \widetilde{V}_A \\ \widetilde{V}_B \\ \widetilde{V}_C \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ a^2 & a & 1 \\ a & a^2 & 1 \end{bmatrix} \begin{bmatrix} \widetilde{V}_1 \\ \widetilde{V}_2 \\ \widetilde{V}_0 \end{bmatrix}.$$

The same transformation also applies to currents. Equivalent sequence circuits are obtained from the relationships between sequence voltages and currents.

Compared to per-phase models, symmetrical components simplify power flow computations by decoupling the equations involving mutual impedances (Figure 2), under the assumption that power systems are perfectly symmetric and energized with balanced sources. As a result, the positive, negative, and zero sequence equivalent circuits can be solved separately. Moreover, ideal balanced sinusoidal operation implies that the only non-zero component of voltage sources is the positive sequence. The solution to the positive sequence equivalent network alone is then sufficient to obtain all system voltages and currents. The consequence of the simplicity of this approach is that most network models for power flow and state estimation use positive-sequence equivalent parameters only.

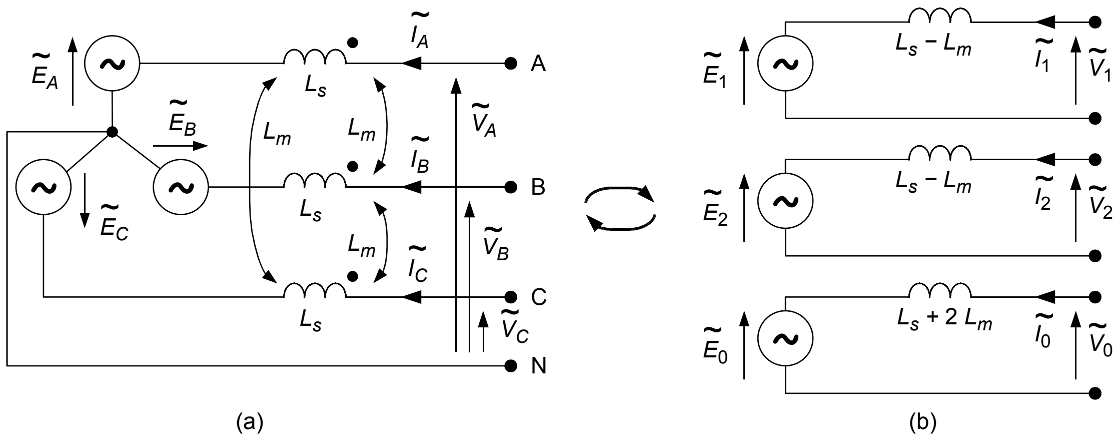


Figure 2: Transformation of a generator model from (a) three-phase to (b) equivalent circuits using symmetrical components.

In reality, certain power system components such as untransposed transmission lines are not symmetric. Because of asymmetries, symmetrical component models introduce a systematic error of about 6 % in per-phase electrical quantities [23]. As a result, the systematic modeling approach with symmetrical components is being reconsidered as high fidelity is nowadays expected from power system models.

2.2.2 Three-Phase Physical Power System Models

Advanced power system models are three-phase physical models that correspond to the physical layout and connections of all phases. Physical models of transmission lines are defined by the type and layout of the cables and shield wires, the geometry of the towers, the line length, soil properties, and more. Physical parameters of motors and generators include the size, materials, and density of stator and rotor windings. Because no approximations or symmetry assumptions are introduced, the simulations of physical models are more accurate than simulations of models that use symmetrical components only.

In three-phase physical models, each phase is modeled separately, and the voltages and currents are computed for each phase individually. Fault currents through each breaker pole capture the asymmetries of the system. In addition, the grounding structures and impedances are an integral part of the network models. Explicit grounding models give mathematical access to the exact impedance of the ground current return path [24]. Indeed, the ground impedance directly affects the ground potential rise and the level of fault currents the breakers have to interrupt.

2.3 Power Flow Equations and Solution

The power flow solution of a network model is the basis for circuit breaker fault analysis and subsequent reliability assessments. Determining how much power flows through each transmission line of a network is thoroughly described in the literature [25, 26, 27]. To solve the power flow problem for sinusoidal steady-state operation, it is sufficient to determine the voltage phasor $\widetilde{V}_k = V_k\, e^{j\delta_k}$ at every system bus k.

The power flow equations express the real (P) and reactive power (Q) balance at every bus in the system. The power balance is written as the equality between the injected power (from generators and loads) and the power carried or lost through the transmission paths to neighboring buses and to the ground. Using the single-line model with positive-sequence admittances $y = g + jb$ and the nomenclature shown in Figure 3, the equations for real and reactive power balance are

$$P_{g,k} - P_{d,k} = V_k^2 \left[g_k + \sum_{m \in K(k)} (g_{k,m} + g_{s,k,m}) \right] - V_k \sum_{m \in K(k)} \alpha_{k,m} V_m, \tag{1}$$

$$Q_{g,k} - Q_{d,k} = -V_k^2 \left[b_k + \sum_{m \in K(k)} (b_{k,m} + b_{s,k,m}) \right] - V_k \sum_{m \in K(k)} \beta_{k,m} V_m, \tag{2}$$

where

$$\alpha_{k,m} = g_{k,m} \cos(\delta_k - \delta_m) + b_{k,m} \sin(\delta_k - \delta_m),$$

$$\beta_{k,m} = g_{k,m} \sin(\delta_k - \delta_m) - b_{k,m} \cos(\delta_k - \delta_m).$$

There are three types of buses: slack (often times, Bus 1), PV, and PQ. Depending on the type of each bus, not all of the power balance equations above can be used to obtain the power flow solution. In a system with n buses, including n_q PQ buses, there are $n-1+n_q$ unknowns or state variables (highlighted in Table 3) and $n-1+n_q$ independent equations that constitute the power flow equations.

Individual load and generator characteristics make the power flow equations (1) and (2) non-linear. Algorithms such as Newton's method or Gauss-Seidel's method are thus used to solve the power flow equations numerically. To increase the accuracy of the power flow results, the solution of a generalized quadratic power flow formulation using Newton's method is presented in Chapter 5.

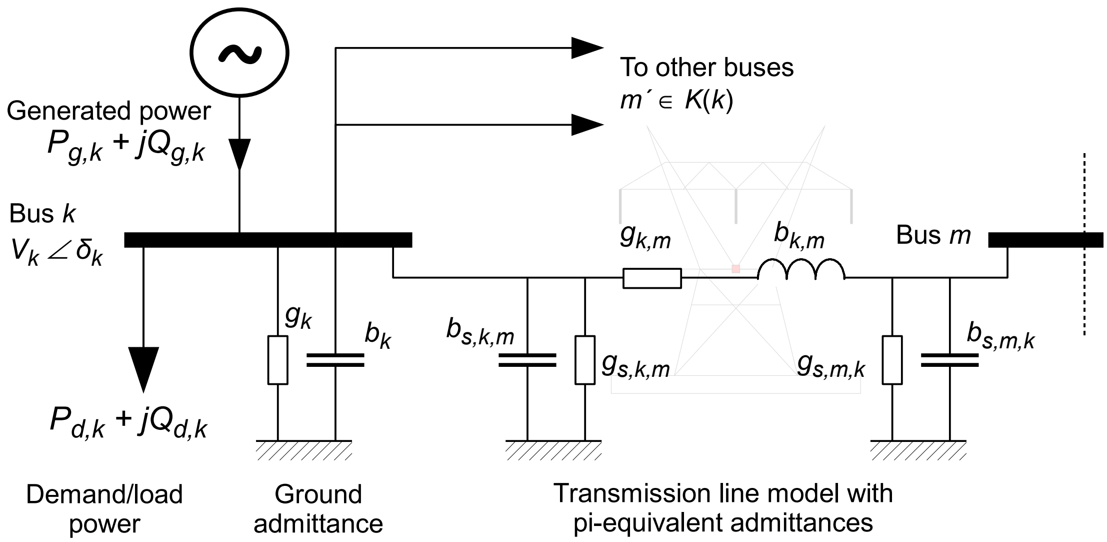


Figure 3: Simplified single-line model of a generic bus and a transmission line.

Table 3: Selection of power flow state variables and equations.

Bus Type	Quantity	Known Quantities	Unknowns and $\boxed{\text{State Variables}}$	Equations to Use
Slack	1	V_1, $\delta_1 = 0°$	$P_{g,1}$, $P_{d,1}$, $Q_{g,1}$, $Q_{d,1}$	None
PQ	n_q	$P_{g,k}$, $P_{d,k}$, $Q_{g,k}$, $Q_{d,k}$	$\boxed{V_k}$, $\boxed{\delta_k}$	(1), (2)
PV	$n-1-n_q$	$P_{g,k}$, $P_{d,k}$, V_k	$Q_{g,k}$, $Q_{d,k}$, $\boxed{\delta_k}$	(1)

2.4 Economic Dispatch with Security Constraints

The economic dispatch (ED) of generators affects fault analysis because fault currents are determined by the capacity of all the generators in service, regardless of the power actually produced. Therefore, the ED is an opportunity to introduce operating constraints related to transmission capacity, natural resources, and fault current levels when it comes to preserving the adequacy of circuit breakers.

The economic dispatch is an optimization process that determines the output power assigned to each generator in the system. It is formally defined as

> the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities (2005 U.S. Energy Policy Act [28]).

Operational constraints are, on one hand, the costs, capacities, resource needs, and startup or shutdown times of the generators, and, on the other hand, the hourly, weekly, seasonal, and weather-related fluctuations of the load. The load pattern used in the IEEE Reliability Test System [29, 30] is shown in Figure 4.

The ED is run by utilities one to several days ahead using load forecasts, and the generator outputs obtained are adjusted during the day as the load varies. Real-time ED is also performed when generating resources must be adjusted within minutes. Only generators with small inertia, such as small turbines, wind farms, or hydroelectric plants, are subject to short-term economic dispatch. Large coal or nuclear plants require much longer times to adjust power, and such plants typically maintain the same power output.

The economic dispatch is achieved in a two-step process. The first step is a pure economic dispatch that assigns real power outputs. The second step is a reactive power (VAR) dispatch that assigns reactive power throughout the system to keep voltage levels in typical operating ranges.

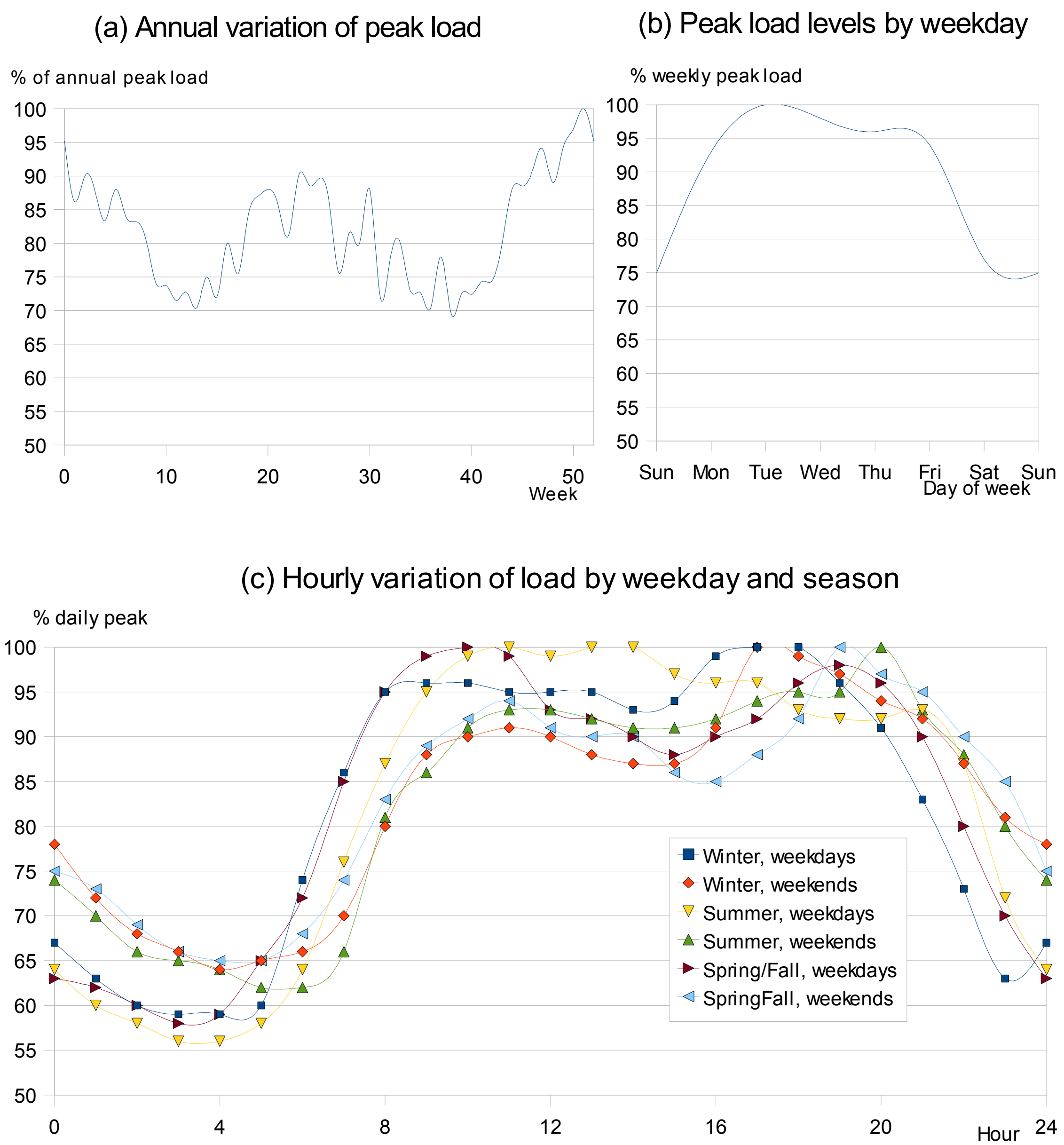


Figure 4: Load model of the IEEE Reliability Test System: (a) seasonal, (b) weekly, (c) hourly by weekday and season.

2.4.1 Generator Cost Function

The cost function f of a generator depends on its output power P_g. This cost function is commonly written in quadratic form as

$$f(P_g) = (a + bP_g + cP_g^2),$$

with a, b, and c being the quadratic cost coefficients for the generator.

The cost coefficients are computed using the rated thermal or heat output of the generators. The quadratic cost comes from two different contributions: operating and maintenance (O&M) costs and fuel costs. In the IEEE Reliability Test System, O&M costs consist of a fixed cost a_{OM} and a variable cost b_{OM} proportional to the output power P_g [29, 30]. Example fuel costs are shown in Table 4 (Jan.–July 2007 estimates [31], except uranium cost [29]).

Table 4: Sample fuel costs for generator operation.

Fuel	Cost (\$/MBtu[a])
Coal	1.77
Uranium	0.60
#2 oil	13.59
#6 oil	7.85
Natural gas	7.37

[a]1 Btu (British Thermal Unit) = 1055 J.

The cost function for one plant can be computed as follows [27]. The column vector $\mathbf{h}$ groups n_h different rated heat rates, in other words, the different amounts of energy to operate the generator per unit time:

$$\mathbf{h} = \begin{pmatrix} h_1 \\ h_2 \\ \vdots \\ h_{n_h} \end{pmatrix}.$$

Let the power matrix $\mathbf{A}$ be defined with the rated output power $P_{r,k}$ associated with each heat rate $h_k, k = 1 \ldots n_h$:

$$\mathbf{A} = \begin{pmatrix} 1 & P_{r,1} & P_{r,1}^2 \\ 1 & P_{r,2} & P_{r,2}^2 \\ \vdots & \vdots & \vdots \\ 1 & P_{r,n_h} & P_{r,n_h}^2 \end{pmatrix}.$$

Let $\mathbf{x_0}$ be the quadratic coefficients for the energy needed to operate the plant per unit time:

$$\mathbf{x_0} = \begin{pmatrix} a_0 \\ b_0 \\ c_0 \end{pmatrix} \text{(in energy per unit time).}$$

Then, the product $\mathbf{Ax_0}$ also contains the different amounts of energy to operate the plant per unit time. As a result, $\mathbf{Ax_0} = \mathbf{h}$.

The least square approximation yields

$$\mathbf{x_0} = \left(\mathbf{A}^T \mathbf{A}\right)^{-1} \mathbf{A}^T \mathbf{h}.$$

Note that the coefficients a_0, b_0, and c_0 do not include the price of fuels p_{Fuel}. The final cost coefficients a, b, and c are therefore

$$\begin{aligned} a &= a_0\, p_{Fuel} + a_{OM}, \\ b &= b_0\, p_{Fuel} + b_{OM}, \\ c &= c_0\, p_{Fuel}. \end{aligned}$$

2.4.2 Pure Economic Dispatch Formulation

The economic dispatch (ED) determines the cheapest combination of generator outputs that provides the real power required for the load and estimated transmission losses under normal conditions. (Power exported to neighboring systems is neglected.) Not all generators are necessarily put in service. For generators that are in service, the assigned power must be between the rated minimum and maximum outputs. This process is called pure economic dispatch because it does not account for factors other than fuel and O&M costs. The pure ED problem is formulated as follows:

$$\begin{aligned}
\text{minimize} \quad & \sum_i f_i(P_{g,i}) = \sum_i (a_i + b_i P_{g,i} + c_i P_{g,i}^2) \\
\text{subject to} \quad & \sum_i P_{g,i} - P_{Load} - P_{Losses} = 0 \\
& x_i P_{g,i,min} \leq P_{g,i} \leq x_i P_{g,i,max} \ \forall \ i \\
& x_i \in \{0, 1\} \ \forall \ i,
\end{aligned}$$

where

$x_i = 1$ if generator i is connected, 0 otherwise (decision variable),

$P_{g,i}$ is the real power output of generator i (decision variable),

$P_{g,i,min}$ and $P_{g,i,max}$ are the minimum and maximum output of generator i, and

P_{Load} and P_{Losses} are the total real power for the system load and estimated losses.

The problem is a mixed-integer problem with a quadratic cost function and linear constraints. The integer variables can be initially neglected ($x_i = 1 \quad \forall \ i$), and the resulting simplified problem can be solved using methods such as Wolfe's decomposition [32]. The integer variables are then set to

$$x_i = \begin{cases} 1 & \text{if } P_{g,i} \neq 0 \\ 0 & \text{if } P_{g,i} = 0 \end{cases} \quad \forall \ i.$$

2.4.3 VAR Dispatch

The VAR dispatch problem assigns the reactive power output of the generators while

- maintaining currents within the ratings of all transmission paths and
- maintaining the bus voltage magnitudes to acceptable values
  (typically, $0.95 \leq V_k \leq 1.05$ p.u. for each bus k).

The solution to the pure economic dispatch problem is the initial guess for the VAR dispatch problem. The generic formulation of the VAR dispatch problem is

$$\begin{aligned}
\text{minimize} \quad & \sum_i w_i \,|Q_{g,i}| + \sum_j w_j \,|b_{cap,j}| + \sum_k w_k \,|b_{react,k}| + M(\Delta P_{Mis} + \Delta Q_{Mis}) \\
\text{subject to} \quad & |I_{i,j}| < I_{i,j,max} \quad \forall (i,j) \text{ pair of nodes } (i \neq j) \\
& V_{i,min} \leq V_i \leq V_{i,max} \quad \forall\, i \\
& 0 \leq b_{cap,j} \leq x_{cap,j}\; b_{cap,j,max} \quad \forall\, j \\
& 0 \leq b_{react,k} \leq x_{react,k}\; b_{react,k,max} \quad \forall\, k \\
& x_{cap,j}, x_{react,k} \in \{0,1\} \;\forall\, j,k,
\end{aligned}$$

where

$x_{cap,j} = 1$ and $x_{react,k} = 1$ if capacitor j and reactor k are connected, 0 otherwise,

$Q_{g,i}$ is the output of generator i,

ΔP_{Mis} and ΔQ_{Mis} are mismatches between the dispatched real and reactive power and the actual real and reactive power demand, and

$I_{i,j}$ is the current between nodes i and j.

($T_{i,j}$ may replace $I_{i,j}$ as the generalized flow between nodes i and j.)

The $[]_{max}$ subscript (e.g. in $I_{i,j,max}$) designates the maximum value of the corresponding variable. The decision variables are $Q_{g,i}$, $b_{cap,j}$, and $b_{react,k}$, weighted by the coefficients w_i, w_j, and w_k, respectively.

The two-step economic dispatch presented above is part of a more complex process that involves a variety of objectives and constraints that include

- minimization of transmission losses,
- power flow constraints (optimal power flow problem),
- emission and environment-related restrictions [33],

- reliability and operational limits of machines, lines, and switchgear, and
- prime mover fuel or natural resource availability.

In this study, the focus is on constraints imposed on power systems operation by the operational and reliability limits of overstressed circuit breakers. Once operational constraints are established, they are integrated into the security-constrained economic dispatch that determines the commitment and output of all generators.

Once an instance of an economic dispatch problem is formulated, a solution can be obtained using a number of optimization methods, such as decomposition, relaxation, genetic algorithms, and particle swarm.

2.4.4 Security-Constrained Economic Dispatch

From its definition in the Energy Policy Act, one important focus of the economic dispatch is the reliability of power systems. Certain reliability levels must be maintained in the case of contingencies (e.g. the absence of one or several generators, lines, or breakers).

To maintain reliability, operational limits are defined to account for transmission lines congestion, system frequency, and voltage levels. Equipment failures occur if the system operated beyond these limits. When the operational and reliability limits are factored into the economic dispatch constraints, the economic dispatch problem is called security-constrained economic dispatch problem. Generator outputs are adjusted accordingly to avoid operating any transmission and distribution device beyond its capacity or reliability limits.

2.4.5 Optimal Power Flow

The power flow problems and economic dispatch problems previously described can be combined together to ensure that the operation of power systems is achieved at the lowest cost while including the constraints of all the generators, loads, and, possibly, circuit breaker operating limits. The optimization problem that results of the combination of the power flow and economic dispatch problems is called the optimal power flow.

The optimal power flow problem is actually an economic dispatch problem in which the power flow equations are included as a constraint. The generalized formulation of an optimal power flow problem is

$$\begin{aligned}
\text{minimize} \quad & \sum_i f_i(P_{g,i}) = \sum_i (a_i + b_i P_{g,i} + c_i P_{g,i}^2) \\
\text{subject to} \quad & g(x, P_{g,i}) = 0 \\
& \sum_i P_{g,i} - P_{Load} - P_{Losses} = 0 \\
& x_i P_{g,i,min} \leq P_{g,i} \leq x_i P_{g,i,max} \ \forall\ i \\
& \text{VAR dispatch constraints} \\
& \text{Other system constraints} \\
& x_i \in \{0, 1\} \ \forall\ i,
\end{aligned}$$

where $g(x, u) = 0$ represent the generalized power flow equations. The decision variables are $P_{g,i}$, $Q_{g,i}$, x_i, and the decision variables of the VAR dispatch problem.

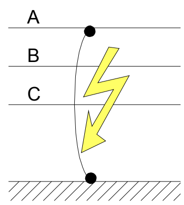
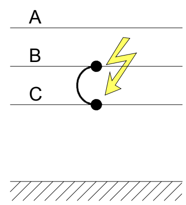
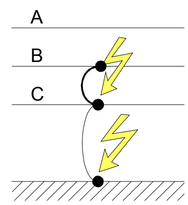
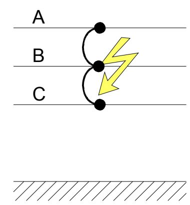
Power systems operations have ramifications in many domains, including generator control, reactive power control, and load management. Circuit breaker reliability introduces a new set of operating constraints for the security-constrained economic dispatch and the optimal power flow. Because it includes constraints from many aspects of power systems, the optimal power flow appears as the backbone of power systems operations.

2.5 Fault Conditions in Power Systems

2.5.1 Overview

Faults (or short circuits) start with the dielectric breakdown of air or insulators, or by direct contact of an external artifact with the conductors. Faults usually occur as a result of insulation defects or undesired line contacts from line or tree sags, critters, storms, and other situations beyond human control. Faults involve one or more phases that are accidentally connected to the neutral, to the ground, or together. A fault is likely to be of one of the types shown in Table 5. The actual probabilities of the faults encountered vary with the environment that surrounds the transmission system.

Table 5: Illustration and typical incidence of power system faults.

Fault Type	Single-phase to ground/neutral	Line-to-line	Line-to-line-to ground/neutral	Three-phase
				
Incidence	80 %	10 %	8 %	2 %

Fault currents are much more intense than regular load currents. All short circuits should be cleared as fast as possible because of the severe stresses (mechanical, thermal, and magnetic) and the dangerous ground potential rise that are imposed on the components of the system.

To avoid equipment damage, protective relays must quickly detect faults, and circuit breakers must isolate the appropriate circuits. Unnecessary wear to circuit breakers and operation of circuit breakers beyond their interrupting capabilities should be avoided to prevent outages. Circuit breakers and other protective devices are described in Chapter 3.

A fault may be the first event of a cascading sequence, where overload protection functions create a snowball effect by transferring the cumulated load from interrupted lines to the lines that remain in service. Eventually, lines are automatically removed one after the other. For instance, the cascading effect that resulted in the North-eastern American blackout in August 2003 started with the disconnection of two transmission lines in Eastern Ohio, USA. These two lines were automatically disconnected after faults were initiated by excessive line sagging and resulting contacts with surrounding trees [34]. Reduced operating margins from this unexpected protection operation did not help the system accommodate the subsequent events that led to the blackout.

2.5.2 Basic Short-Circuit Analysis

The root mean square (RMS) value of the current at the time of circuit breaker operation is the quantity of interest to assess breaker adequacy because it determines the intensity of the electric arc, contact erosion, and subsequent dielectric recovery conditions. After the onset of a fault, the RMS value of the current through a breaker increases and varies with time. The exact RMS value of the interrupted current depends on the actual time of breaker operation.

Short-circuit currents consist of a symmetric (AC, sinusoidal) component and a decaying asymmetric (DC) component [35, 36] (Figure 5). The exact magnitude of the DC component depends on the nature of the fault and the power factor at the inception of the fault.

In single-phase equivalent models, the RMS value I of the AC component is

$$I = \frac{V}{\sqrt{R^2 + (\omega L)^2}}, \tag{3}$$

where V is the voltage of the equivalent source of the system, ω its pulsation, and R and L are the equivalent resistance and inductance of the faulted circuit.

The expression for the RMS value of the total fault current as a function of the time t ellapsed after the onset of the fault is

$$I_F(t) = I\sqrt{1 + 2e^{-2\frac{R}{L}t}}. \tag{4}$$

The maximum RMS value of the total fault current is $I\sqrt{3}$ at $t = 0$ (at the inception of the fault). From Equation (4), the DC offset can increase the magnitude of the interrupted current by a factor as high as 1.73. The DC component decays exponentially at a rate governed by a DC time constant $\tau = L/R$.

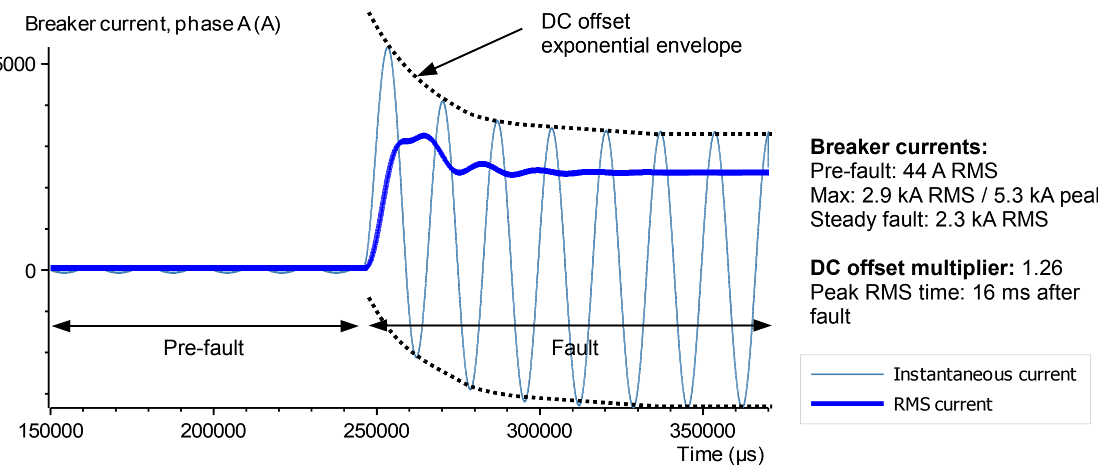


Figure 5: Illustration of the DC offset on fault currents.

The X/R ratio is commonly used in place of L/R ($X = \omega L$). The X/R ratio reflects the prevalence of the inductance in the whole system. Standard values of the X/R ratio are 14 and 17 at 50 and 60 Hz, respectively, and correspond to $\tau =$ 45 ms [37]. The DC time constant τ increases with conductor concentration [38] (especially in dense urban areas), the addition of distributed sources, and, more generally, changes in the resistive and reactive properties of power systems equipment [39]. High values of τ mean slow decay of the DC offset and increased breaker duties. Hence, the X/R ratio affects circuit breaker stresses and reliability levels.

2.5.3 Fault Currents and Circuit Breaker Ratings

Before 1964, circuit breakers were rated using the RMS value of total fault currents, with both AC and DC components included. Since 1964, circuit breakers are rated based on the RMS value of the AC component of fault currents only [40]. The DC offset accompanies most faults, causing the total RMS current to be slightly higher than the AC RMS current alone. The same rule applies to breaker ratings: ratings based on AC currents only are smaller than ratings that include the DC offset. Cases may arise where breakers properly rated using total fault currents may be underrated using the AC component of fault currents only. Without supporting evidence, it is impossible to determine whether a breaker is rated following the pre-1964 or the post-1964 standards. Such situations may be dealt with field tests or using a conservative circuit breaker rating.

2.6 Circuit Breaker Operational Limits and Power Systems Operation

The particularity of circuit breaker operational limits lies in the infrequent nature of circuit breaker operations. Circuit breakers do not present any reliability issue or hazard as long as they remain closed, whether fault currents exceed their interrupting capability or not. In other words, circuit breakers are not the limiting constraint when considering the SCED based on steady-state currents.

In contrast, breakers may fail when triggered to clear fault conditions. Interruption success or failure cannot be predicted because the internal condition of the breaker and the magnitude of currents during the next fault cannot be observed. Because the interruption success or failure is not known until after the actual breaker operation, breaker failures are called *hidden failures* [41].

Because all breaker failures are hidden failures, the quantification of breaker failure rates is challenging. Because fault current magnitudes are not known in advance, statistical or probabilistic methods are necessary to estimate breaker stresses and failure rates.

One highlight of the proposed work is to formulate and quantify circuit breaker operational limits that serve as constraints for the economic dispatch and unit commitment problems. The integration of such constraints in power system operations results in benchmarks to achieve set levels of system reliability.

2.7 Summary

Operational concepts of power systems, such as power flow, economic dispatch, and basic fault analysis, are presented in this chapter in the light of assessing circuit breaker adequacy. A general formulation of the respective mathematical problems is provided. Fundamentally, the power flow and the available generating capacity in normal operation are the initial conditions to determine fault currents through circuit breakers and assess breaker adequacy. In other words, the stresses and reliability of circuit breakers derive from the power flow and economic dispatch.

As faults randomly strike during day-to-day operations of power systems, protection naturally complements power systems operation. Protection schemes are designed to prevent power systems from exceeding the operating limits defined in the economic dispatch and power flow problems. Therefore, effective and reliable protection against power system faults cannot be achieved without an understanding of power systems operation and the different protection mechanisms in use. Chapter 3 is devoted to a presentation of the characteristics and limits of circuit breakers, protective relays, fault current limiters, and substation layouts that are the basis on which protection schemes are built.

CHAPTER III

UNDERSTANDING POWER SYSTEM PROTECTION DEVICES

3.1 Power System Protection Philosophy

The philosophy of power systems protection has not fundamentally changed despite technological progress. Effective power systems protection is essential to minimize the impact of faults on electrical equipment, including mechanical stresses, thermal stresses, and power quality problems. Effective protection relies on

- fast fault detection;
- fast and selective fault clearing to minimize the affected area; and
- reliable operation of protection devices to reduce occurrences of widespread, common-mode outages.

Circuit breakers are central to power systems protection. They are often called the "last barrier to protect other parts of a circuit or a network against faults" [42]. Unfortunately, circuit breakers are also the weakest elements of protection schemes, since many power outages involve a breaker failure [43]. With increased fault currents caused by power systems growth, many circuit breakers are to become overstressed, and the probability of outages caused by a breaker failure is bound to increase.

This central position of circuit breakers is reinforced by the roles and limitations of other protective devices, such as protective relays and fault current limiters. Therefore, the focus of this chapter is on a functional description of circuit breakers, protective relays, and fault current limiters. Also, since breakers provide flexible and redundant connectivity inside substations, the effect of substation breaker arrangements on the protection and reliability of power systems is also discussed.

Two emerging issues of the power systems protection landscape are the need for offline testing of protection schemes and the coordination of protection schemes with distributed generation (DG). Both of these issues are relevant to circuit breaker adequacy: first, relay testing ensures, using simulated conditions, that overstressed breakers are not operated when fault currents excess their ratings. Second, the integration of DG in the protection schemes of distribution networks allows relays to disconnect DG during fault conditions. Circuit breakers that are overstressed with DG connected may be brought back within their interrupting capability once DG is disconnected and the fault currents contributed by DG are removed. Protection scheme testing is described in Section 3.3 dealing with relays. Integrating DG in the protection of distribution networks is discussed in Chapter 4, where existing practices are reviewed.

3.2 Circuit Breakers

3.2.1 Functional Challenges

According to IEEE and IEC definitions, a circuit breaker is

> a mechanical switching device, capable of making, carrying, and breaking currents under normal circuit conditions and also, making and carrying for a specified time and breaking currents under specified abnormal circuit conditions such as those of short circuit [44, 45].

A high-voltage circuit breaker is depicted in Figure 6. Circuit breakers are protective, heavy-duty switches that must obey specific constraints:

> When closed, breakers are good conductors, and they withstand normal and short-circuit currents, thermally and mechanically.
>
> When open, they are excellent insulators, and they withstand the voltage

to ground or to the other phases, and the voltage between contacts.

When closed, they can interrupt a rated short-circuit current quickly without generating an abnormal voltage.

When opened, they can close a shorted circuit quickly and safely without incidental contact erosion [46].

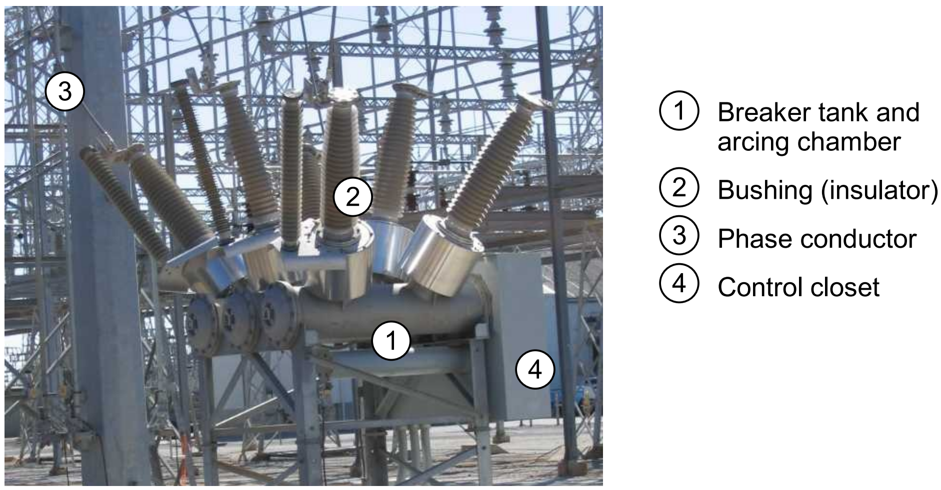


Figure 6: Picture of a high-voltage, outdoor circuit breaker at the San Francisco/San Mateo substation (courtesy Pacific Gas and Electric Company).

In addition, breakers must operate in specific environments without creating hazards. Explosives, dust, humidity, and seismic regions illustrate frequent extreme conditions for circuit breaker operation.

Because of these constraints, maintaining high circuit breaker reliability is critical and challenging. Most technical requirements of high-voltage circuit breakers can be found in IEEE and IEC standards. The main technical aspects and references relevant to circuit breakers are presented in this section.

3.2.2 Electric Arcs and Switchgear

Electric arcs were discovered independently by Vasilii Petrov from Russia in 1802 and Sir Humphrey Davy from England in 1808 [47, 48]. General works on arcs and plasmas [49, 50, 51] rely on fundamental theories established by Cassie, Browne, and Mayr.

Electric arcs are essential to circuit breaker operation, and their role is thoroughly described in the literature [42, 46, 52, 53, 54].

The highly inductive nature of power systems makes it impossible to interrupt currents instantaneously. At power system voltages, any attempt to open an energized circuit results in an electric arc appearing between the separated contacts. After contact separation, the current continues flowing as long as the arc exists. In one experiment, an impressive electric arc was obtained (and video-taped) after a disconnect switch failed to open a 500-kV line that was carrying only 100 A [55]. Despite the failure of the disconnect switch, the arcs from the experiment are insignificant compared to the ones associated with faults that draw 100 times the normal current.

An electric arc is a narrow, bright, and conductive plasma channel. The ionization from the plasma may extend to surrounding liquids, gases, and electrode (contact) materials. Arcs appear when the space (or gap) between two contacts has not acquired the dielectric strength to withstand the system voltage (up to 800 kV). The typical temperature of the core of an arc is between 6000 °C and 20,000 °C. (Higher values can be reached in vacuum breakers [42, 50].) Of course, the size, temperature, and brightness of an arc increase with the current through the arc.

The destructive nature of an arc comes from its high temperature and from the pressure wave associated with a steep temperature gradient between the core and the outside of the arc. (The temperature of an arc changes from 20 °C to 6000 °C over a few millimeters.) Arcs gradually erode the contacts of circuit breakers after each fault interruption. If not properly interrupted, arcs with a destructive power that is orders of magnitude higher than with arcs used in soldering can cause extensive equipment damage and serious injuries.

Low-frequency arcs (below 1 Hz) may self-extinguish if there is enough time for such arcs to cool down; however, at power system frequencies, arcs do not extinguish by themselves. For example, a 30 kV, 50 Hz arc burning between plates 1 meter apart does not extinguish spontaneously [42]. In addition, the more current carried in an arc, the more difficult it is to extinguish that arc. The main challenge for circuit breakers is to extinguish very intense arcs that are created when opening a faulted line.

The key to interrupting an arc is to bring the instantaneous current through the arc to zero. In AC circuits, the current crosses zero twice per cycle. In DC circuits, the current does not alternate, and it must be forced to zero either by increasing the arc voltage or by injecting an opposing current. Since DC circuits are marginal in major transmission systems, they fall out of the scope of this study.

In AC power systems, when the instantaneous current of an arc reaches zero, that arc stops burning. The gap that is established between the arcing contacts starts recovering its dielectric properties by recombination of electrons and ionized molecules. The first objective of a circuit breaker is to extinguish arcs, and this objective is spontaneously achieved.

When a breaker extinguishes an arc, the inductive nature of power systems causes the voltage between the breaker contacts to shortly peak between 1.5 and 3 times the system voltage. This voltage spike is known as the *transient recovery voltage* (TRV). A simulated TRV waveform is shown in Figure 7; actual TRV waveforms from measurement records can be found in the literature [56]. At this point, the second objective of a breaker is to prevent a restrike. IEEE standard C37.011 [57] specifies the TRV that circuit breakers must withstand during the moments (milliseconds) following the extinction of an arc. If the TRV increases fast enough and exceeds the dielectric strength of the gap, the arc restrikes; the resurrected arc must be extinguished again at the next instant of zero current. When opening a faulted circuit, if an arc restrikes while the breaker is fully open, the breaker failed to interrupt the fault [58].

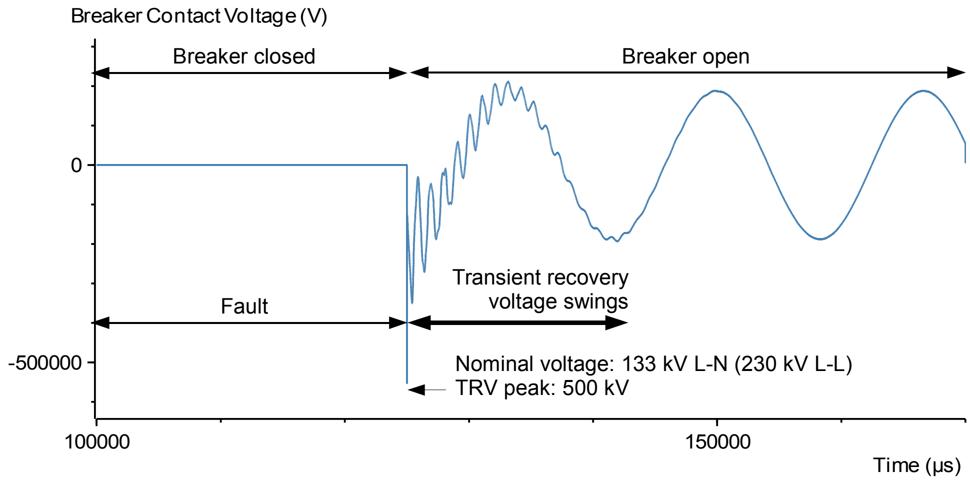


Figure 7: Simulated transient recovery voltage waveform across the poles of a breaker after fault interruption.

The environment in the gap can be altered to accelerate arc quenching (extinction) and prevent restrikes. In some SF_6 breakers, fresh gas is blown into the gap to accelerate the recombination of molecules. In air-magnetic breakers, arcs may be artificially elongated using the magnetic field of the fault current itself.

To conclude, although electric arcs are an essential part of fault interruption, circuit breakers must extinguish them fast and prevent a restrike; otherwise, faults are not isolated. Therefore, the mechanical components of circuit breakers are designed for a quick separation of contacts (within 2–10 cycles of the beginning of the fault), and the insulating medium must have fast dielectric recovery.

The various mechanical components and insulating media of circuit breakers are discussed next. The reliability of these components are the basis of the proposed circuit breaker reliability model presented in Chapter 5.

3.2.3 The Interrupting Medium

Circuit breakers are characterized by their interrupting media because of the central role played by these insulating materials in circuit breaker operation. Indeed, the interrupting medium directly participates in arc quenching, withstands the system voltage, and prevents restrikes and accidental flashovers across open breaker contacts.

Air, oil, vacuum, and SF_6 are the most common dielectric materials used in circuit breakers. Key properties of these interrupting media are listed in Table 6.

Table 6: Typical properties of circuit breaker interrupting media.

Material	Air	Oil	Vacuum	SF_6
Max. voltage (kV)	15/765[a] [59]	360 [59]	38	800
Cost[b]	N/A	\$3/gal. [60]	N/A	\$20/lb [61]
Availability	~1900/1940[a]	1900	1962	1955 [62]
Dielectric strength[c] (MV/m)	1–3	10 [53]	N/A	5 [63]
Supports combustion	Yes	Yes	No	No
Toxic	No	Yes	No	No
Corrosive	Yes (O_2)	Yes (pollution)	No	Yes (byproducts)
Colors/odors	None	Oil	None	None
Density[c] (kg/m^3)	1.2	800–900 [64]	10^{-9} [59]	6.2 [65]
Pollution-proof	No	No	No	Yes
Recovery speed of dielectric strength	Slowest	Intermediate	Faster	Fastest
Environmental impact	None	Oil spills	None	Strong greenhouse gas

[a]Applies to air blast circuit breakers.
[b]Estimated material costs.
[c]At 1 bar, ambient temperature (except vacuum).

Oil was the first and preferred interrupting medium until the advent of gas circuit breakers [59]. Air breakers emerged with the arc-chute mechanism that artificially elongates and divides arcs into small sections that are easy to extinguish. Air-blast breakers accommodate high-voltage arcs by blowing high-pressure air into the plasma [52]. Vacuum circuit breakers are particular because the low pressure (10^{-4} to 10^{-1} Pa [66]) and the lack of materials is turned into an advantage to interrupt arcs. Vacuum breakers are well-suited for medium-voltage applications up to 38 kV; above that level, SF_6 is preferred for contact insulation [50].

Sulfur hexafluoride is a very dense gas (five times heavier than air), has a superior dielectric strength, and quickly recovers from ionization [67]. Despite remarkable insulating properties, SF_6 should not be released in the atmosphere. With 22,000 times the greenhouse power of carbon dioxide (CO_2) [68], specific procedures to handle SF_6 have been developed [69, 70] to help maintain the releases of this gas at insignificant levels compared to other greenhouse gases [71]. Alternatives to pure SF_6 as an insulating material (e.g. SF_6–N_2 mixtures) have also been experimented [72].

3.2.4 The Operating or Trip Mechanism

Trip mechanisms provide the energy necessary to move the contacts of a circuit breaker from the closed position to the fully open position as fast as possible. This energy either is stored or directly provided by auxiliary power supplies. The most common circuit breaker operating mechanisms are described in Table 7.

Because the contacts are mechanically supported, contact parting is not instantaneous. The total opening time may take a few cycles (e.g. 40 ms or 2 cycles at 50 or 60 Hz in the most recent breakers [73]).

Table 7: Typical circuit breaker operating mechanisms.

Operating Mechanism	Description
Spring	The spring is charged with a motor or hydraulically. Latches lock the breaker in one position or the other.
Pneumatic	Contacts are actuated using the sole force of compressed gas (air, SF_6).
Hydraulic	Similar to pneumatic. Leaks are reduced using a liquid actuator (oil) that exhibits the same behavior over a wide range of temperatures.
Magnetic	Latches are actuated through the magnetic field generated by an energized trip coil.
Motor-driven	An electric motor moves the contacts of the circuit breaker.

3.2.5 Factors that Determine Circuit Breaker Ratings

The rating or interrupting capability of a circuit breaker is the highest current a breaker can interrupt without degrading its reliability level. The rating, reliability, and performance of a circuit breaker is dictated by the design of its different parts. The design criteria for high-voltage circuit breakers are governed by two comprehensive sets of standards from IEEE and IEC.

3.2.5.1 Design Factors

Contacts The arc interruption process takes place at and between the breaker contacts. The material, geometry, and spacing of the contacts determine the characteristics of the gap during circuit breaker operations. The geometry of the gap determines the environment in which arcs are extinguished. In addition, the construction of the contacts affects their ability to sustain frequent or repeated arcing.

Arc Quenching Components The insulating medium dictates the maximum voltage that can be applied across the contacts of an open breaker during steady-state and transients, without creating flashovers. More importantly, the insulating medium directly participates in arc quenching, either passively or actively. Breakers with puffer-type mechanisms achieve superior interrupting capabilities by combining strong insulating media (such as SF_6) and active arc quenching mechanisms that circulate the insulating material through the arcing space.

Trip Mechanism The faster the trip mechanism separates the contacts, the faster faults are cleared, the shorter the arc duration, and the less the breaker and the rest of the system have to sustain stresses from high fault currents. Fast contact separation may also help the interrupting medium recovering its dielectric strength. The fault clearing time should account for the effect of the DC offset and the duration of the stresses sustained by the equipment.

Each element of a circuit breaker is built to operate successfully under specific fault conditions. These conditions are communicated to the end-user as the rated operating voltage and rated fault currents. The actual capability of a circuit breaker is affected by manufacturer design margins and contact wear [74]. These margins are selected by manufacturers to meet certain criteria, including the requirements of both IEEE and IEC standards [75] and to account for performance degradation with the number of operations and with time.

A diagram summarizing how circuit breaker ratings relate to the different breaker components and how breaker ratings determine the interruption success of fault currents is shown in Figure 8.

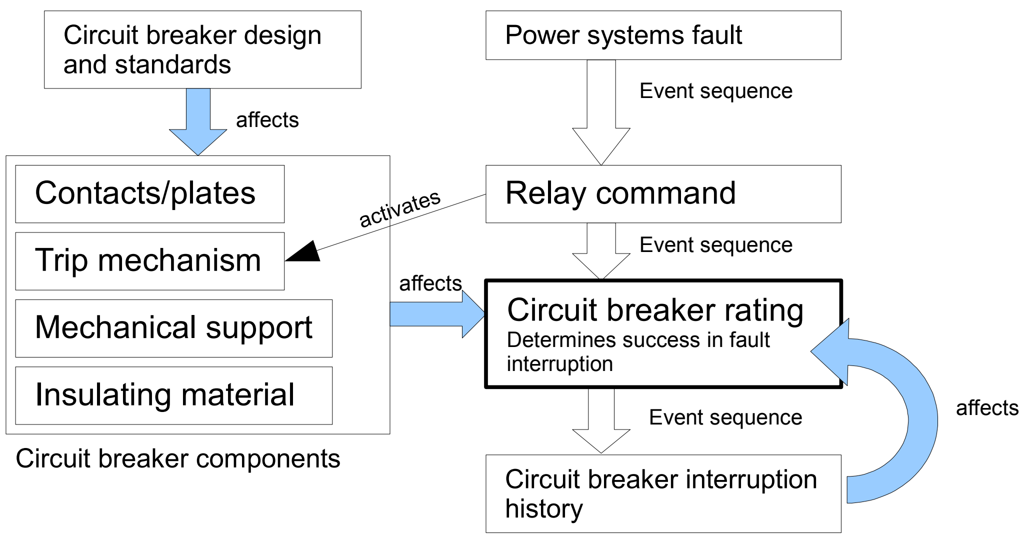


Figure 8: Sketch of the interaction of breaker components during fault interruption.

3.2.5.2 Standards for Circuit Breaker Ratings

During the first few cycles that follow the inception of faults, the DC offset increases the total RMS value of fault currents (and the actual stresses applied to circuit breakers) above the RMS value of the AC portion alone. As seen in Chapter 2, the fault current RMS value can be increased by as a factor as high as 1.73, depending on the delay between fault initiation and the opening of breaker contacts.

The rating basis for circuit breakers changed in 1964 from the total RMS value of fault currents (AC and DC components combined, ANSI/IEEE C37.x standards) to the RMS value of the AC component alone (C37.0x standards). The change took place to simplify and to harmonize ANSI/IEEE standards with international standards [40]. The DC offset can be obtained from the AC portion of short-circuit currents using Equation (4), knowing the equivalent X/R ratio and the breaker clearing time.

The transition from one rating standard to another implies that, without supporting evidence, it is impossible to determine whether an old breaker is rated according to the pre-1964 or the post-1964 standards. Certain breakers properly rated using total fault currents may be underrated based on the AC portion of fault currents only; spcific actions should be taken to establish the reliability of such breakers.

The uncertainty on the nameplate rating of the oldest breakers propagates to their actual interrupting capability when accounting for age and interruption history. The rating based on total fault currents is conservative but helps avoid overestimating the rating of an old breaker. This means that if the rating of a circuit breaker is 40 kA, the 40 kA value already includes the DC offset, and the breaker rating without the DC offset is less than 40 kA. In sum, the margins to maintain the adequacy of circuit breakers are reduced when considering total fault currents as opposed to fault currents without the DC offset.

3.2.5.3 Interrupting Capability Testing

Circuit breaker testing standards ANSI/IEEE C37.09 and IEC 60056 define design tests and production tests [42]. Design tests include withstanding rated voltages and currents, withstanding TRVs, close-open cycles at different current magnitudes, mechanical endurance, and the integrity of enclosures and sealing. Production tests cover the performance of the trip mechanism and the breaker circuitry.

Design tests (such as the test of the interrupting capability of a breaker) are heavier than production tests and may destroy the tested breakers. No utility can risk the loss of a breaker while attempting to determine its actual rating. As a result, unlike other performance parameters, circuit breaker ratings cannot be "measured" in the field, and the nameplates and interruption history are the only information available to estimate the interrupting capabilities of circuit breakers.

Generating the rated breaking current of a circuit breaker at power system voltages requires large power supplies that can emulate fault conditions. The largest breaker testing facility is the KEMA High Power Laboratory, located in Arnhem, the Netherlands. The "short-circuit generators" of that facility can provide up to 10,000 MVA at 60 Hz [76]. Also, the facility has dedicated test circuits for different applications, such as the testing of 550 kV, 63 kA line breakers [77] or the testing of 27.5 kV, 120 kA generator breakers [78]. Special circuit breakers protect the KEMA laboratory against the extremely high fault currents drawn during the tests.

If the required fault currents cannot be generated at a testing facility, then circuit breakers are tested on the grid itself (at the expense of some safety and reliability).

3.3 Protective Relays

3.3.1 Functional Characteristics

Digital relays from several manufacturers are shown in Figure 9. The relays shown are part of a substation automation laboratory at the Georgia Institute of Technology.

Relays contain and execute the protection schemes that are absolutely necessary to protect power systems. The design of protective relays and protection schemes has been extensively studied in academia and industry [79, 80, 81]. Protective relays monitor the electrical variables of circuits they protect, through potential and current transformers (PTs and CTs) that scale voltages and currents down to 115 V and 5 A nominal, respectively. Using these scaled measurements, relays implement a set of specialized functions that detect conditions such as short circuits, voltage sags, frequency drifts, etc. If a condition is detected by a relay function and the condition lasts longer than a predefined duration, then the appropriate circuit breakers are automatically triggered.

Figure 9: Picture of different types of digital protective relays mounted on racks.

Protective relays have been widely used since the end of the 19$^{\text{th}}$ century for two purposes: the protection of high-voltage transmission systems [82] and the protection and signaling of electrified city railroads [83, 84].

3.3.2 Electromechanical vs. Numerical Relays

Electromechanical relays open and close protection circuits as a response to the magnetic forces and the thermal effects that accompany abnormal voltages and currents. Protection circuits trigger circuit breakers when certain relay states are simultaneously met. Electromechanical relays are equipped with dials that determine their operating thresholds (voltages and currents) and time delays.

The protection offered against one abnormality (e.g. overcurrents, voltage sags) is called a *function*. An electromechanical relay implements one protection function only. Protection against multiple abnormalities requires multiple functions and multiple electromechanical relays. The calibration and testing of electromechanical relays is challenging because of the inherent inaccuracies in the construction of these relays and the limited number of standard ratios for potential and current transformers [85]. The drawbacks of electromechanical relays are therefore in (i) the number of relays required to build a comprehensive protection scheme and (ii) the calibration and testing required for the correct operation of each relay utilized.

Numerical (computer-based) relays were introduced in the late 1960s to take advantage of the advanced signal processing capabilities of microprocessors [86]. Numerical relays implement comprehensive sets of protection functions and can be finely configured to produce a specific response to any power system event.

3.3.3 Protection, Margins, and Coordination

One could argue that detecting and clearing short-circuit currents before they become too intense is the way to operate overstressed circuit breakers. Such an argument would obviously void the interest of the proposed study. Three practical reasons explain why it is not possible to interrupt faults at the very instant they initiate.

The first reason is to avoid undesired relay operations during transients and temporary overloads (when carried currents exceeds rated line currents). Utilities overload certain transmission corridors by 5 to 20 % to compensate for the lack of transmission capacity when the demand peaks [87]. In addition, motor startup and transformer magnetization typically draw currents at least 6 times above nominal levels. Although relays are configured to pickup at levels above nominal currents, overload and inrush currents must be permitted for a certain duration before a line is tripped.

The second reason is a consequence of the coordination of different relays. When a fault occurs, the relays and circuit breakers that are the closest to the fault (where fault currents are highest) operate and disconnect the faulted area. Modern relays trigger circuit breakers within one cycle. If a fault persists beyond a certain duration (because of a relay or breaker failure), backup relays trigger additional circuit breakers and remove power from an area wider than initially intended. Relay coordination is typically achieved using several protection zones, each activated with a different time delay. In the coordination example shown in Figure 10, a fault in Zone 1 causes the focused distance relay to operate the associated circuit breaker after one cycle. If a fault occurs in Zone 2 or Zone 3, the focused relay is no longer the closest one to the fault, and it is delayed to allow appropriate relays and circuit breakers to operate first; in this particular case, the focused relay acts as a backup relay.

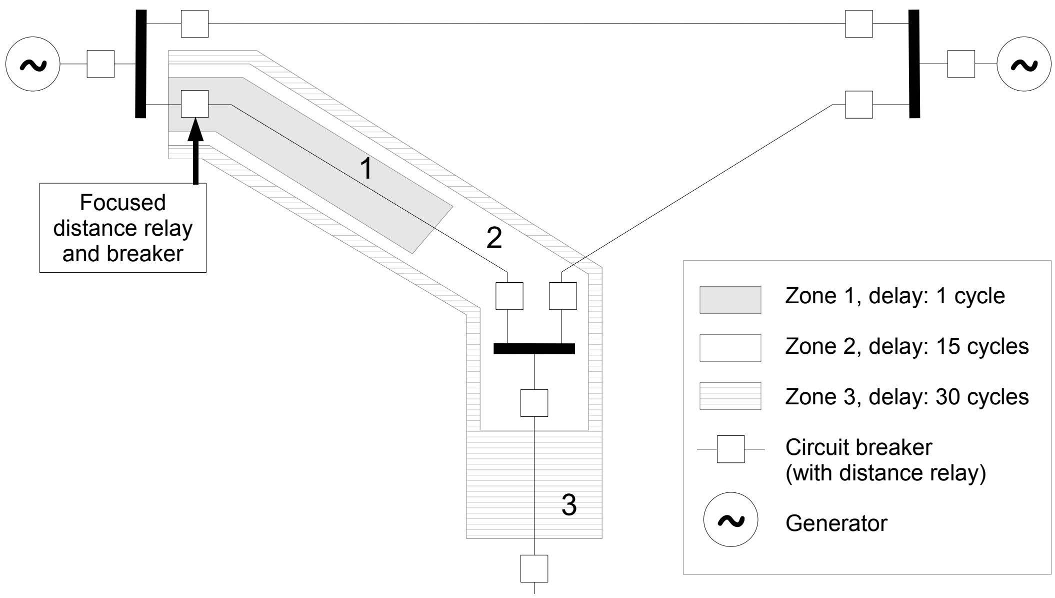


Figure 10: Example of distance relay application with three protection zones.

If backup relays were to trip instantaneously, large portions of the system would be unnecessarily disconnected every time there is a fault. This is especially true for distribution systems that usually have a radial structure. Therefore, backup relays (and breakers protecting Zones 2 and 3 of transmission lines) normally have a longer response time (15–30 cycles) than relays directly surrounding the fault. One exception to this rule is when backup breakers have higher ratings than first-zone breakers. In such cases, if the first-zone breaker is overdutied, backup breakers should be triggered first to avoid breaker failures and common-mode outages.

The third reason is the time it takes to actually operate relays and clear faults. With major relay manufacturers, instantaneous relay operation implies operation within one cycle. Half a cycle is the typical minimum relay response time used in IEEE standards and by utilities [37, 88, 89]. In numerical relays, such a response time is needed to obtain an adequate sample of fault currents before the current RMS can be computed. The relay response time and the contact parting time of the circuit breakers create a cumulative delay of one to a few cycles before arcing and current interruption actually start. In contrast, the initial rise of fault currents takes less than half a cycle. After this rise, the RMS value of fault currents obeys Equation (4) until fault conditions are cleared.

It results that clearing faults within the first half-cycle of a fault for the purpose of "benefiting" from reduced fault currents is not possible with the equipment presently available. Finally, although arcs should be extinguished at the zero current crossing immediately following the parting of the breaker contacts, the whole arc quenching process may take a few additional cycles. The timing and order of the different steps to clear a fault are synthesized in Figure 11.

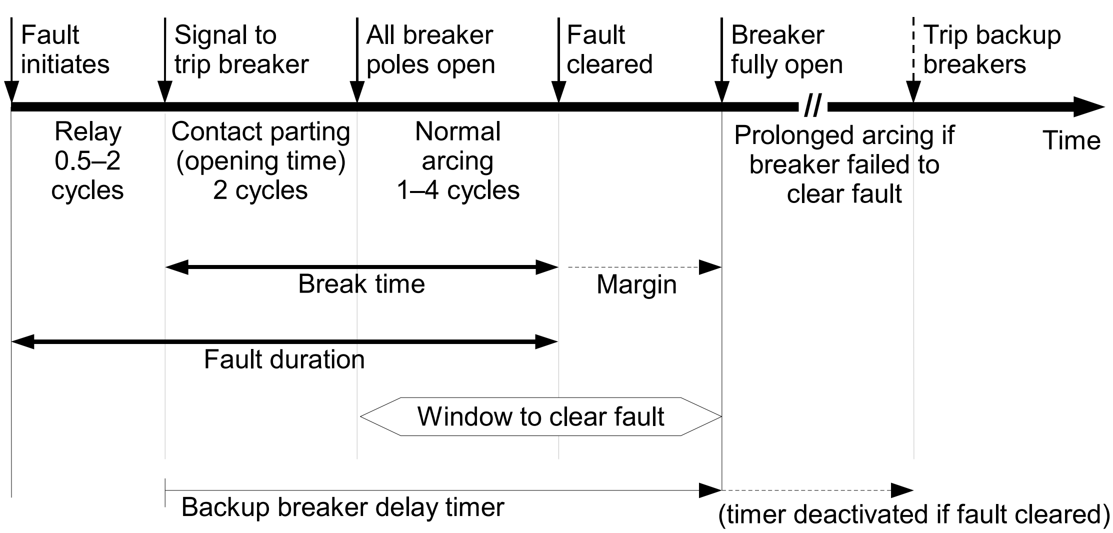


Figure 11: Sequence and timing to clear a fault (modified from IEEE C37.04 [40]).

To summarize, it is not practically possible to operate circuit breakers and clear faults at the exact instant they occur. Relay margins and coordination prevent the arc quenching process from starting (and completing) before short-circuit currents largely exceed nominal currents.

3.3.4 Testing of Numerical Relays and Phasor Measurement Units

Relay testing is relevant to preserving circuit breaker adequacy because it is an opportunity to ensure, through offline simulations, that overstressed breakers are not operated beyond their interrupting capability.

More generally, numerical relay testing is important to track unexpected relay responses to certain power system events. Relay misoperations were the initiating circumstances of two recent blackouts [90, 91]. Besides, utilities have developed an interest in testing relays and protection schemes against various power system events or transients. Moreover, the compatibility and interoperability of relays from multiple vendors can be assessed during these tests. In addition to transient testing, there is a growing interest in testing the measurement and timing accuracy of GPS-synchronized equipment (relays and phasor measurement units).

3.3.4.1 Principle

The principle of a relay test is as follows: a fault, voltage sag, frequency drift, or any other transient phenomenon is simulated; the corresponding potential transformer (PT) voltages and current transformer (CT) currents are recreated and fed to the tested relay; finally, the response of the relay or the accuracy of the tested PMU is analyzed (Figure 12).

Commercial products can perform a predetermined palette of tests. In addition, laboratory experiments are being developed to improve the accuracy and the scope of such tests. For instance, timing accuracy is obtained using waveform generators with high-precision clocks [92]. Waveform accuracy is achieved by simulating three-phase, physical power system models that include all circuit breakers and instrumentation devices; the quadratic integration method further improves the accuracy of time-domain waveforms [93]. Waveforms that reflect field conditions can also be obtained using scaled models of power systems, where imbalances and power quality issues can be reproduced and tested [94, 95]. With present testing equipment, high levels of power system fidelity can be achieved to respond to the specific relay testing needs from utilities and system operators.

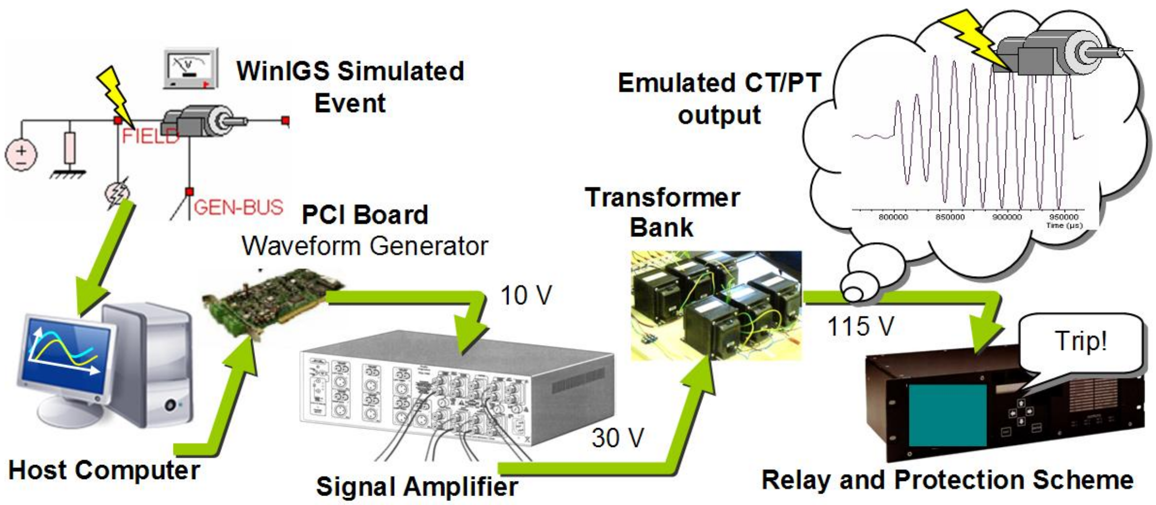


Figure 12: Relay testing workflow.

3.3.4.2 Transient Testing of Protection Schemes

Approaches have been investigated by IEEE and PSERC researchers to provide a unified relay testing methodology that transcends the differences in setup and functionality between relays from different manufacturers [96]. Transient testing of protective relays generally relies on the following methodology:

- A reference test system (for example, a model of the local bulk transmission system) is designed to simulate the events and transients of interest.
- Benchmark scenarios that target the functions that are common to the tested relays are drafted. The scenarios include simulated events and recorded data

from actual transients. The expected responses of the tested relays to these events are compiled.

- Using a programmable voltage and current source, transient waveforms are played and sent to the tested relays.
- The responses of the relays to the transient waveforms are collected for analysis.

As suggested in Figure 12, a significant hardware platform (a commercial relay testing device or a waveform generator built from scratch) is required to recreate the CT currents and PT voltages for the relay inputs. Specifically, voltages and currents are simulated on a computer, then converted into 115 V/5 A signals through D/A converters and amplifying equipment. The limited number of channels available and the range of the generated voltages and currents are challenges that restrict the spectrum of the tests that can be conducted.

On the other hand, since modern relays are computer-based, virtual relay testing can be performed on a host PC without a hardware platform (Figure 13). Measurement inputs and relay outputs are processed as the simulation runs. Feedback is provided in real-time to help identify discrepancies in protection schemes.

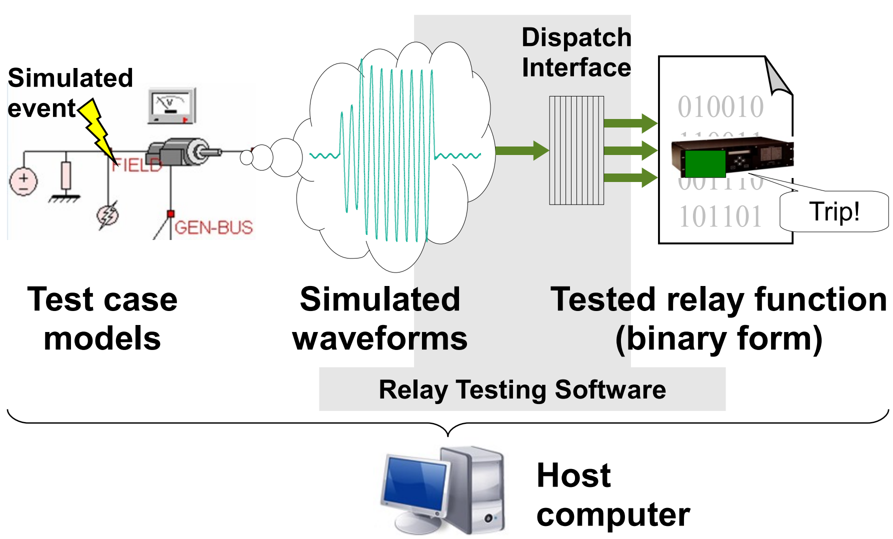


Figure 13: Principle of virtual relay testing.

Virtual relay testing relies on the ability to send configuration and waveform data to the relay firmware directly without using PT or CT circuits. The events and outputs of the tested relay can be processed directly as well. A documented interface [97] is needed for different parties to understand how waveform data and tap settings are used within the tested relay firmware. Such tests are technically possible but require close cooperation with relay manufacturers. Moreover, with the knowledge of the interface parameters of relay binaries from multiple vendors, the computer running the tests can dispatch a single input to the different relays using the formats accepted by each relay function. As a result, virtual relay testing eliminates the constraints of a hardware setup, including waveform generation, wiring, and communications. By removing the restrictions on the possible range of tests, virtual relay testing opens opportunities for advanced relay testing techniques. An open system approach would allow utilities, universities, and manufacturers to collaborate and improve the state of the knowledge in protective relaying [98, 99, 100].

3.3.4.3 PMU Measurement and Timing Accuracy Testing

The measurement and timing accuracy of relays and PMUs are critical to successful state estimation and *postmortem* event analysis. Indeed, the time for an event to propagate to PMUs scattered across an electric network may result in measurements shifted by several degrees at 60 Hz. PMUs improve the ability to find the signature of the same event from waveforms recorded at different locations. To determine the measurement and timing accuracy of relays and PMUs, a reference waveform is sent to those devices, and the measurements retrieved from the devices are compared to the reference waveform. Drifts in magnitude, frequency, and timing are tabulated.

The accuracy and interoperability of PMUs are subject to the IEEE Standard for Synchrophasors for Power Systems [101]. In addition, the North American SynchroPhasor Initiative (formerly Eastern Interconnection Phasor Project) has completed (a) a test guide to unify PMU testing [102], including proper time-stamp assignment and (b) a guide for assessing the accuracy of synchrophasor measurements [103]. The testing procedures described are under implementation at NIST and at the Georgia Institute of Technology [92, 104].

The objective for these tests is to obtain phasor measurements with an ideal accuracy of 0.1 % in magnitude and 0.01° in phase angle (0.5 μs at 60 Hz).

3.4 Fault Current Limiters

Fault current limiters (FCLs) are variable-impedance devices with two states: the default, "permissive" state (low, transparent device impedance) and the "limiting" state (increased device impedance under fault conditions). With their variable impedance, fault current limiters can

- limit fault currents in circuits that are not rated to carry the full fault current,
- limit the duty of circuit breakers to allow reliable breaker operation, and
- divert currents in excess of the rating of a line to neighboring lines.

The impedance of a fault current limiter can be increased in several ways. Explosives and fuses were used in early limiters to abruptly open or change the impedance of the circuits. Modern limiters are based on superconductors and/or semiconductors. In high-temperature superconductors, the temperature and impedance increase with the current [105]. (The upper limit for superconductivity is −173 °C.) In contrast, semiconductor current limiters are activated by the output of a relay and transfer the current to a high-impedance shunt device. Fault current limiters exist for voltages up to 500 kV [106].

Fault current limiters are praised for their ability to improve electric power quality and system stability [107]. They can mitigate the increase of fault currents resulting from distributed generation while delaying the need to replace overdutied circuit breakers. The greatest need for FCLs is in dense and highly interconnected systems, such as the Japanese grid [108].

Newly installed equipment must not compromise power systems reliability. Specific precautions must be taken when equipping lines with fault current limiters. First, to avoid exceeding breaker ratings, FCLs must bring the highest possible fault currents below the ratings of potentially overstressed breakers. The situation where fault currents remain above the ratings of the breakers after FCL operation is known as "overshooting" [109]. The second precaution is to ensure proper coordination of FCLs with protective relays [110, 111, 112]. FCLs affect three factors of power systems protection: (i) the magnitude of stresses, (ii) the timing of the protection (FCLs may operate faster than relays), and (iii) the phase angle of fault currents [113].

The last precaution relates to the automatic reclosing of circuit breakers. Since many faults are transient rather than permanent, relays often attempt to open and reclose circuits several times within the seconds following a fault. To avoid interferences with existing protection schemes, FCLs must return to the permissive state before circuit breakers reclose. Although semiconductor-based FCLs can switch to the permissive state instantly, superconductor-based FCLs take a few minutes to cool down and cannot operate until they reach the superconductive state again [105].

The characteristic conditions resulting from the operation of FCLs must be detected and treated as fault conditions. Indeed, protection schemes may not respond to certain low residual fault current levels, and residual fault current levels can still generate dangerous ground potential rises.

Fault current limiter technology is still under development. With costs expected to decline, FCLs are to become widespread and improve the operations of power systems.

Prioritized FCL deployments can be determined from the methodology proposed in this study to relieve the operations of the most overstressed breakers. The expected improvements in power system operations earned fault current limiters the reputation of "Holy Grail" [105] devices.

3.5 Bus and Substation Protection

In substations, circuit breakers are arranged in a way that allows taking a single line out of service without disconnecting other lines. Protection and instrumentation equipment are also present on the substation premises. Substations constitute the nodes of the transmission system.

Most high-voltage substations are outdoor substations, such as the one visible in the background of Figure 6. Indoor substations are less common and support lower voltage levels than outdoor substations.

In certain substation configurations, fault currents can flow from one point to the other through multiple paths. Each path receives a fraction of the total current drawn by the fault. The topology of circuit breakers and lines in a substation dictates the range of fault currents the breakers must interrupt. Indeed, unlike breakers devoted to the protection of a single line, breakers that are part of a substation ring bus or a transfer bus must be able to interrupt the highest fault current on any of the lines connected to that substation [114]. Therefore, substation topologies affect circuit breaker adequacy and reliability.

3.5.1 Types of Arrangements

Circuit breakers are arranged to provide connectivity between lines and the ability to isolate one or several lines independently from the rest of the system. Many breaker arrangements also allow at least one breaker to be out of service while maintaining full connectivity between any two points within the substation. The typical substation breaker arrangements that can be combined to achieve connectivity are single-breaker, transfer buses, ring, double-bus-double-breaker, breaker-and-a-half arrangements [114] (Figure 14).

3.5.2 Advantages and Drawbacks

Each of the substation breaker arrangements presented in Figure 14 has advantages and disadvantages in terms of maintenance flexibility, construction cost, and path redundancy. The number of breakers per line determines the construction cost of the substation. The number of breakers needed to open a line determines whether fault currents from a line are divided between one or several paths within the substation; multiple breakers that protect the same line guarantee the redundancy of its supply. The outage allowance is the highest number of breakers that can be open or withdrawn for maintenance while maintaining full substation connectivity. The number of breakers per line, the number of breakers to open a line, and the outage allowances for each bus-breaker arrangement shown in Figure 14 are listed in Table 8.

Table 8: Comparative characteristics of bus-breaker arrangements.

Arrangement	Breakers/Line	Breakers to Open Line	Outage Allowance
Single-breaker	1	1	0 breaker
Transfer bus	$1 + 1/n_{Lines}$ [a]	1	1 breaker
Ring	1	2	1 breaker
Double-breaker	2	2	50 % of breakers
Breaker-and-a-half	1.5	2	33 % of breakers

[a] n_{Lines} being the number of lines connected to the considered group of breakers.

The ring bus and the breaker-and-a-half arrangements are common because they balance the number of breakers per line with the outage allowance while maintaining a redundancy of the line connections. These bus arrangements cost less than double-breaker arrangements but retain the benefits of redundant connection. In terms of reliability, ring and breaker-and-a-half arrangements support $N-1$ contingencies with at least two degrees of freedom (two routes to supply any transmission line).

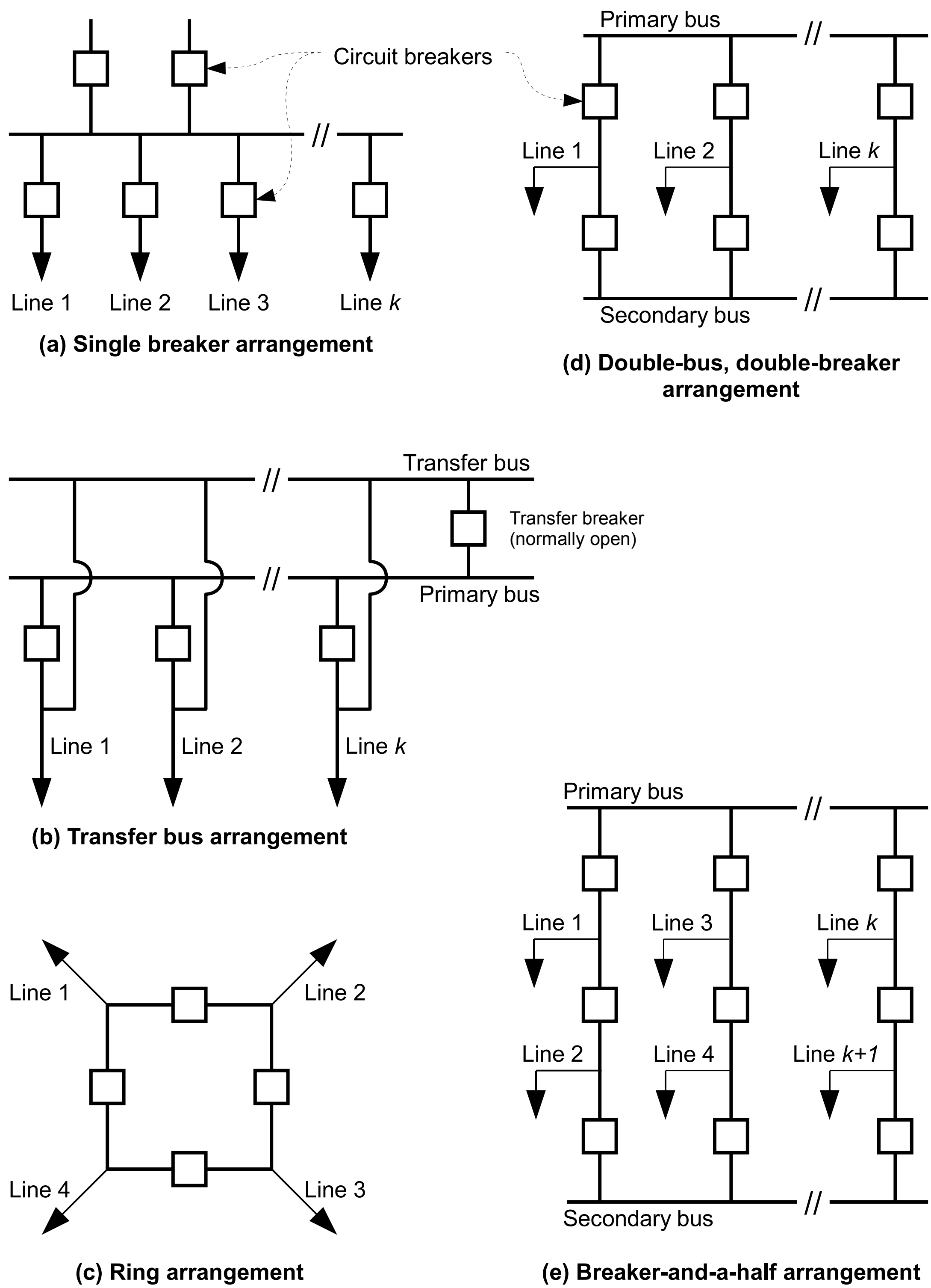


Figure 14: Illustration of typical substation breaker arrangements.

3.6 Summary

Functional descriptions of circuit breakers, protective relays, and fault current limiters are provided in this chapter. Each device plays a protective role and affects the duty and reliability of circuit breakers. Their role and limitations must be considered when designing and testing protection schemes.

Circuit breakers are central to power systems protection because they ultimately interrupt fault currents and protect other equipment against the mechanical and thermal stresses caused by high fault currents. The different parts of a circuit breaker participate in the different stages of fault interruption: relay-breaker links must transmit all relay trip signals to breaker trip mechanisms; trip mechanisms ensure that the contacts of the breakers open as fast as possible while avoiding unnecessary wear on mechanical parts; mechanical parts, in contrast, must endure open-close sequences as specified in circuit breaker standards; not least, breaker plates accelerate arc extinction and maintain dielectric insulation once the breaker contacts are open.

The ratings and reliability of circuit breakers are determined by the design characteristics of the different breaker components. Thus, interrupting fault currents that exceed the capabilities of circuit breakers is unsafe and should be avoided because of the increased risk of breaker failures, associated common-mode outages in other parts of the system, and the accelerated aging of the breakers that may jeopardize pre-established maintenance plans. The role played by each of the breaker components is integrated into a Markov chain model of circuit breakers that is based on the reliability models of the individual breaker components. This Markov model is developed in Chapter 5 and serves as the base to build a lifetime model of circuit breakers.

Around circuit breakers are relays that sense and react to fault conditions. Future relay applications should account for circuit breaker ratings; appropriate protection strategies should address events where a breaker does not have a sufficient rating to interrupt a given short-circuit current. Fault current limiters and substation configurations come as an aid to reduce the duties of overstressed breakers and to control the flow of fault currents through all the substation paths. In Chapter 6, several strategies are investigated, where substation topologies, breaker switching sequences, and fault current limiters contribute to the control of the fault duty of overstressed breakers.

CHAPTER IV

REVIEW OF EXISTING KNOWLEDGE AND PRACTICES

4.1 Overview

The objective of this chapter is to review existing practices and works as relate to circuit breaker monitoring and fault duty management. Managing breaker duties, especially in distribution systems with distributed generation, and monitoring breaker status to detect early performance degradation and signs of failure, appear as keys to improving circuit breaker operational reliability.

This chapter is divided in several parts that deal with

- on-site circuit breaker duty and wear monitoring,
- circuit breaker maintenance practices,
- existing strategies to circumvent circuit breaker overstress,
- applications of breaker-oriented network models,
- statistical estimation of circuit breaker fault duty, and
- protection of distribution systems with distributed generation.

4.2 Impact of Distributed Generation on the Protection of Distribution Systems

4.2.1 About Distribution Systems

Distribution systems are the part of power systems that link customer loads to the hubs and substations of transmission systems. While transmission systems generally connect main generation and load centers over long distances, distribution systems have a much finer layout than transmission systems to serve all customers of a particular area.

Most distribution networks have a radial structure (Figure 15) that originates at a transmission substation and has ramifications to all customer loads of the serviced area. Although two branches of a distribution system may be interconnected at specific locations to form a mesh (using tie switches), meshed distribution networks are less common than radial distribution networks [115, 116].

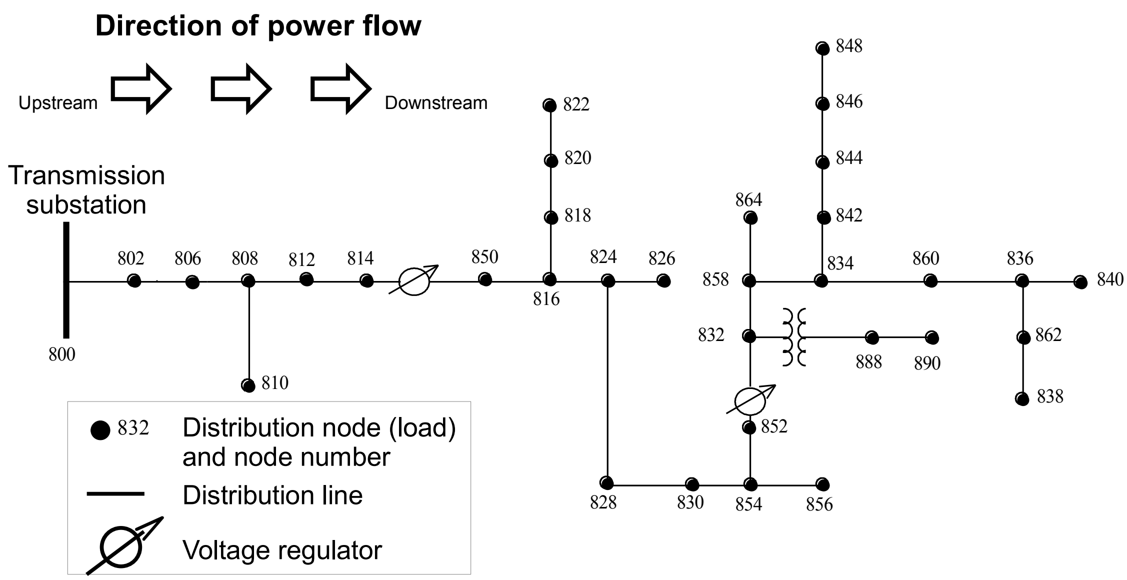


Figure 15: The IEEE 34-bus radial distribution test system [117].

In the absence of distributed generation, the knowledge of the different sections of a radial distribution system is sufficient to conduct fault analysis and to design protection schemes. In radial distribution systems, fault analysis and protection coordination are relatively simple because the current flows in a single direction, from the transmission substation to the branches and load centers. For each node in a radial system, there is an upstream (towards the substation) and a downstream direction (away from the substation). Since power flows away from substations, there are no power exchanges between the different branches of a distribution system (no “cross-branch” flow). Meshed distribution systems are less common than radial distribution systems; upstream and downstream directions still exist in meshed distribution systems but are determined by loads and fault characteristics.

4.2.2 Distributed Generation and Distribution Systems Protection

Distributed generation is most often found in distribution systems for the proximity to customers (medium and low voltage levels). Although transmission substations provide most of the power carried in distribution systems, distributed sources account for an increasing portion of the power supplied to the loads from within distribution systems.

Several authors have reported that distributed generation (DG) impacts fault analysis and protective relay coordination [7, 115] in distribution networks. The reason for this impact is that the presence of generators in a distribution system blurs the upstream/downstream concept. Distributed generation affects the magnitude and direction of fault currents in certain sections of distribution systems, and protection schemes must be adjusted to account for these changes.

Distributed sources can be viewed in two ways: as small generators compared to the plants that supply most of the power to the distribution network considered, and as primary power sources for the loads at proximity of distributed sources.

The fault current contribution from DG must be compared to fault currents brought by the parent transmission system. On one hand, DG can significantly contribute to fault currents in remote portions of a distribution network, in which case protection schemes must be adjusted to treat such current levels as faults. On the other hand, if DG is located near the origin of a substation feeder, the contribution of DG to fault currents may be small compared to the contribution from the transmission system.

Fault currents drawn by DG must be detected in all cases, however, because

(i) isolating the distribution system from the transmission network alone does not completely isolate faults as DG may still feeding them, and (ii) some utilities require DG sources to be shut down or disconnected from distribution systems during faults.

4.2.3 Typical Protection Procedures and Issues in Systems with Distributed Generation

To avoid electrocution hazards to utility crew operating on electrical installations, DG systems are disconnected or shut down during faults or repairs to distribution networks. Islanded operation is generally not allowed without prior utility approval.

Disabling DG during faults seems to defeat one key benefit of DG, which is to provide power and voltage support following a power system event. Disconnecting DG systems from the main distribution system presents the other drawback of requiring a synchronism check when reconnecting a DG system operated as an island.

The full disconnection of DG in a radial distribution system during a fault means that all loads downstream of the breaker that clears the fault is left without power. A tie connection is necessary to enable DG during a fault without islanding and needing to check for synchronism. Distribution systems protection issues are best understood graphically with the aid of Figure 16.

To maintain DG during a fault and continue supplying power to most customers, the principle of the loop has been utilized [115, 118]. When a fault occurs, the supervisory system attempts to establish a loop by closing a tie switch that connects the faulted branch to another part of the distribution system. With the loop in place, at least two breakers are needed to isolate the faulted section of the distribution network. The rest of the distribution network outside of these two breakers is not affected by fault isolation and can continue operation with DG enabled.

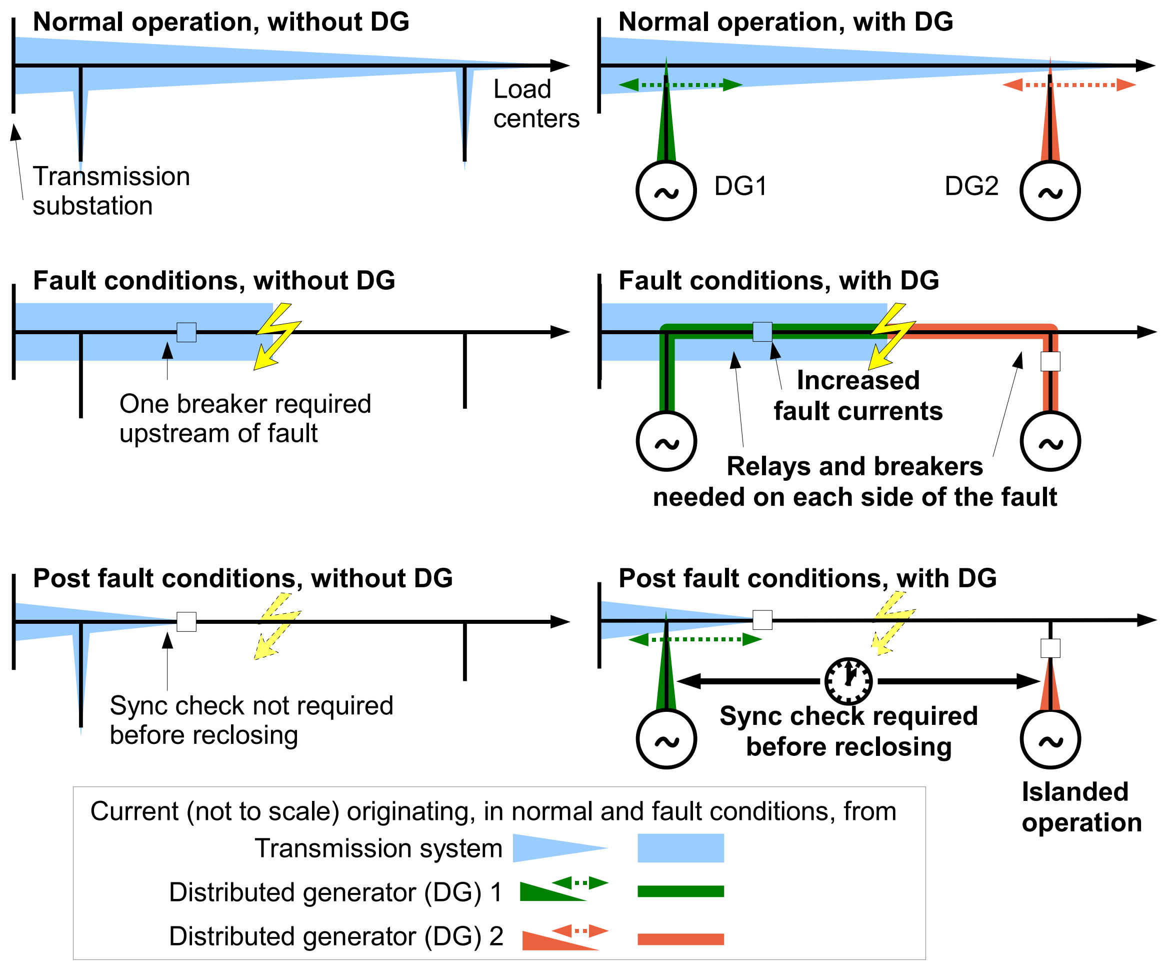


Figure 16: Effect of distributed generation in the protection of distribution systems.

4.3 Circuit Breaker Reliability Analysis and Lifetime Management

4.3.1 Circuit Breaker Reliability Models and Applications

Several circuit breaker reliability models are related to this study. These models attempt to predict breaker failure and maintenance based on operational and maintenance data of the different parts of a circuit breakers.

One circuit breaker reliability model [119] predicts the age-related failures of several breaker components: trip latch, chains, springs, auxiliary contacts for the operating mechanism, insulators, and interrupter unit. The high level of detail of the model allows targeting reliability studies to the individual components of the breaker. Based on limited, general breaker failure statistics (fraction of breaker population that has failed, time and number of operations to failure), the failure rates of the individual components of the breaker are calculated.

The second model [120] is a probabilistic maintenance model that predicts the probability of breaker failures based on the performance findings from maintenance operations. Breaker maintenance is performed based on the condition of the different parts of a circuit breaker. The condition of the breaker components is monitored by a palette of inspection tests. The results of these inspection tests conducted prior to maintenance are utilized to compute a component failure rate and to decide on the type of maintenance that should be performed (from light cleaning of the components to a complete breaker replacement). The type of maintenance performed is partly based on failure costs compared to the costs of actually performing the maintenance. This second model is hence a maintenance-based reliability model.

The third model [121] is a multi-state Markov model of circuit breakers geared towards preventive breaker maintenance. As with the second model, the Markov chain described models the transitions of a particular breaker from states that do not require preventive maintenance to states that require maintenance. In this model, a number of power systems events are simulated, and contingencies are ranked based on the failure probabilities found for each breaker according to maintenance practices for the considered breakers.

The approach taken in these models is opposite of the approach of this study, which is to predict breaker failures based on individual component failure rates. Nonetheless, the theoretical concepts used in these breaker models are also used in the proposed breaker reliability model that includes the effect of increased fault stresses.

4.3.2 Circuit Breaker Duty and Wear Monitoring

The adequacy of a circuit breaker is typically evaluated using worst-case scenarios, for instance, by comparing its rating to the maximum currents contributed by three-phase faults in the studied system [122, 123, 124]. (Three-phase faults are usually more severe than faults of other types.)

Although worst-case scenarios provide an absolute measure of the adequacy of circuit breakers, they do not necessarily reflect the currents that are actually interrupted during the service life of a particular breaker. While interrupting worst-case fault currents may cause immediate breaker failures, wear and tear primarily originates from clearing faults that are not as severe as worst-case faults.

The distinction between worst-case and actual fault conditions is important because actual conditions can be monitored and tracked by numerical relays [74, 125], and fault statistics can be built upon the recorded fault data.

Several circuit breaker monitoring functions already exist in numerical relays, such as tracking the circuit breaker duty, counting of the number of operations, and issuing alarms when the fault clearing time exceeds a preset value. The monitoring functions are implemented using sensor data, including electrical and mechanical quantities. In addition to the voltages and currents of interest, sensor data may contain additional information about the mechanical or chemical condition of the circuit breaker. For instance, the coil current of a breaker carries information about the condition of its trip mechanism [126]. Other relevant data include travel time, gas pressure, fluid levels, and measurements of the dielectric strength of the insulators.

The authors of the papers cited in the paragraphs above mention a number of implementation challenges such as knowing the design, the rating, and the history of currents interrupted. With little to no data available from utilities, the estimates of the statistical distribution of fault current magnitudes proposed in this study are an aid to monitor circuit breaker duty and wear.

4.3.3 Endurance Testing and Modeling

Investigative tests that target the mechanics and insulation of circuit breakers have been completed and documented [127, 128]. Generally, the properties of the contacts, mechanical support, and insulation change slightly after each breaker operation, depending on the severity of the fault. Degradation of the breaker components occurs as these changes are cumulated over time.

In one model, the remaining lifetime of a circuit breaker is estimated by categorizing fault currents into different ranges (e.g. 50 %, 75 %, and 100 % of the rating of the breaker) and by determining the equivalent contact erosion for each range of currents [127, 128, 129]. In another model, circuit breaker wear is based on a set number of operations above which breaker failure rates increase. Each breaker operation is treated as a "shock," which intensity depends on the severity of the interrupted fault. Every shock results in some random wear of the operated breaker [130].

One common aspect of the endurance models above is the consideration of a limited range of fault current values or a limited number of faults. Such limitations reduce the viability of the estimates of circuit breaker wear. Wear predictions can be improved using statistical estimates of the expected stresses through each breaker. Probabilistic distributions of fault current magnitudes for each circuit breaker can be estimated using a system-level fault analysis methodology that includes the most common types of faults. This methodology is developed in Chapter 5. Such distributions quantify the likelihood of the different levels of stresses that may apply to the given breaker at the time of operation.

4.3.4 Maintenance Strategies and Failure Prevention

There are four alternatives when dealing with equipment reaching the end of its initial service life: lifetime exhaustion ("use-it-up", "run-to-failure"), retrofitting, reconditioning, and replacement [131, 132] (Table 9). The total ownership costs of each alternative (including depreciation, maintenance costs, penalties for unavailability, etc.) and the costs associated with the desired performance of the considered circuit breakers determine which alternative is selected by each utility.

Table 9: Description of key equipment usage patterns.

Usage Pattern	Description	Cost
Use-up	The entire service life of the considered equipment is exhausted. The equipment is used until frequent failures become a logistical and financial obstacle to regular operation and maintenance. This pattern typically applies to obsolete equipment.	Lowest
Retrofit	The considered devices are modernized and upgraded with enhanced ratings, functions, and reliability. Compatibility is maintained with the equipment counterparts that have not been retrofitted.	High
Re-conditioning	The considered equipment is brought to its “as new” state with the repair or replacement of most of its parts. Parts must be available for re-conditioning to take place. Although performance is restored to its original point, no additional function, reliability, or performance improvements occur during re-conditioning.	Low
Replacement	New equipment is purchased to meet new performance levels or design standards. A redesign of the interface between the new breakers and the existing substation equipment may be necessary.	Highest

In 1999, a survey on the impact of maintenance on the reliability of power systems investigated the implementation of how four key maintenance strategies at different utilities worldwide [133] (Table 10). The most common maintenance strategies are (a) scheduled maintenance programs at fixed intervals and (b) empirical predictive maintenance based on condition monitoring. It is noted that maintenance increases the lifetime of a device only if failures occur as a result of a deterioration or aging process. Maintenance against random failures does not improve the expected device lifetime, however.

Table 10: Description of key equipment maintenance strategies.

Maintenance Type	Description	Usage
Scheduled (preventive)	Maintenance is performed at regular, fixed intervals, regardless of the deterioration state of the equipment.	Extensive
Predictive (as needed)	Field observations and condition monitoring are carried out regularly. Maintenance is performed if certain criteria from the field observations are met.	Extensive
Reliability-centered maintenance (RCM)	Maintenance is performed with priority given to activities that benefit to the reliability of the system at the most effective cost. Criteria for RCM implementation may vary with utilities.	Emerging
Probabilistic maintenance	Reliability indices are computed based on mathematical models of the power system operations. Maintenance is undertaken as a result of the comparison of different reliability indices.	Emerging

The authors of the survey stress that scheduled maintenance and empirical predictive maintenance are inherently ineffective despite being popular. Specifically, the scheduled and empirical strategies may result in maintenance performed more frequently than actually needed. Thus, these maintenance strategies prevent utilities from fully exploiting the "lifetime potential" of their equipment and from allocating maintenance resources where it is really needed. In addition, the authors of the survey point that unnecessary maintenance exposes the internal components of circuit breakers to additional human errors and may actually increase breaker failures.

Probabilistic maintenance models based on mathematical lifetime estimations have the potential to predict failure more accurately than in condition-based maintenance and without the risk of human error. Despite the advantage of accuracy, these models require historical data that are not always available. According to the cited survey, such mathematical models have still not been used to a significant extent.

The fact that probabilistic models have not been widely used suggests that the focus of the most common maintenance strategies is not on maintaining the adequacy of circuit breakers. New maintenance strategies should emphasize circuit breaker adequacy and be based on probabilistic maintenance models. Indeed, probabilistic models allow factoring historical fault data into future trends, and statistical fault analyses are needed to account for the evolution of circuit breaker adequacy. Statistical fault data are not accounted for in the fixed and as-needed maintenance routines. On the other hand, the statistical data can be accommodated in probabilistic models and be used to compute reliability indices for the reliability-centered maintenance (RCM) strategy. A probabilistic model to evaluate circuit breaker adequacy is developed in Chapter 5.

4.3.5 Maintenance and Lifetime Models

4.3.5.1 Maintenance Models

The goal of maintenance models is to schedule maintenance as to maximize uptime while maintaining desired equipment reliability at the lowest cost and with the resources available. Therefore, there is an important economical emphasis in maintenance models.

Increases in fault duties caused by the growth of generation capacity may shorten the time between maintenance operations. Rising fault current levels are presently not considered in long-term maintenance schedules. Indeed, circuit breaker maintenance is not performed based on the cumulated interrupting duty over the service life of the breakers, and there are no known references of maintenance strategies that anticipate an increase of fault duties as a result of the expansion of the generating capacity.

4.3.5.2 Estimation of Loss of Life

Loss-of-life (LOL) estimation is commonly performed on transformers [134]. Transformer protection relays from major manufacturers calculate the LOL by monitoring the transformer load. Transformer relays may also shed load if the estimated loss of life adversely affects transformer reliability. Specifically, it is established that the life of the insulation of a transformer is drastically shortened above 110 °C [135].

Stresses make the difference and the similarity between circuit breakers and transformers. On one hand, breakers operate a few times per year, whereas transformers are continuously loaded. On the other hand, transformers are overloaded on purpose to save copper (typically at 1.5 times the rated apparent power), whereas breaker overstress is generally unintended.

4.4 Existing Strategies around Circuit Breaker Inadequacy

Replacing overdutied circuit breakers in a short time window is not possible economically and from a manufacturing standpoint. As a result, a number of overdutied circuit breakers must remain in operation. Different ways to circumvent breaker adequacy issues are suggested in papers that describe the experience of utilities [123] and industrial customers [9, 10, 136, 137]. The suggested solutions with their advantages and drawbacks are listed in Table 11.

Table 11: Possible Strategies to Circumvent Overdutied Breaker Issues.

Strategy	Advantages	Drawbacks
Replacement	Durably mitigates the problem.	Expensive, long-term investment.
Swap	Uses existing equipment.	Labor-intensive; limited benefits.
Fault current limiters and current limiting reactors	Mitigates the problem.	Technology not mature yet.
Use of reactors	Reduces fault current.	Prevents efficient motor startup; some voltages may drop. Qualified as "band-aid" solution by some authors [137].
System/substation reconfiguration	Uses flexibility of existing substation or system.	Not a permanent solution; requires a flexible infrastructure.
Selective current tripping and zone interlocking	Uses existing breakers to clear most faults; uses highly rated backup breakers for faults that overdutied breakers cannot interrupt.	Adequate backup protection, relay communication, and relay coordination required for currents above breaker rating.
Delayed relay operation	DC offset neglected.	Tests of new protection scheme necessary.
Sequential tripping	Reduces fault current through overdutied breaker one contribution at a time.	Power removed from an area wider than intended.
Area auto-reclose cycle	Allows overdutied breakers to open safely while surrounding breakers temporarily remove power.	Adversely affects power quality in a large area.

4.5 Uses of Breaker-Oriented Power System Models

4.5.1 Overview

Substation breakers are assumed closed and are omitted in many power flow and short-circuit computations (Figure 3 in Chapter 2). Models that do not include circuit breakers and substation topologies are said to be *bus-oriented*.

In contrast, *breaker-oriented* power system models explicitly represent breaker arrangements inside substations. Breaker-oriented models make power flow and fault analysis possible for any breaker in the studied system. Such models are necessary to accurately check the duties of individual circuit breakers [114] because possible fault currents may vary from one location to another within the same substation depending on which breakers are open or closed. An example to illustrate the differences between the bus-oriented and the breaker-oriented modeling approaches is shown in Figure 17.

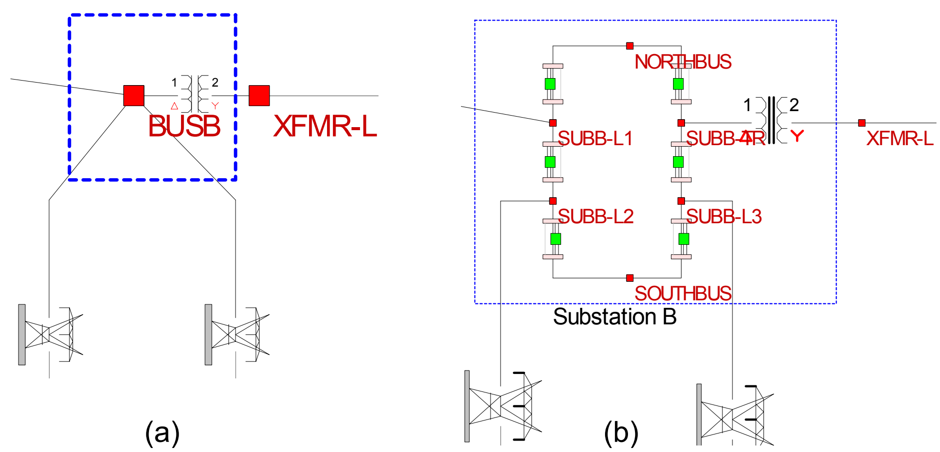


Figure 17: Illustrative comparison between the (a) bus-oriented and (b) breaker-oriented modeling approach.

Bulk power system models with explicit substation breaker arrangements have been introduced with the 1996 definition of the IEEE Reliability Test System [30]. Although breaker arrangements have been integrated to this test system, no comprehensive implementations and applications of three-phase, breaker-oriented reliability test systems have been widely distributed prior to the system proposed in Chapter 7.

Breaker-oriented network models have not been widely used because the conversion of substations from single nodes to groups of multiple nodes dramatically increases the size of the modeled power systems. Additional state variables (one state per breaker) are needed to compute the power flow through each circuit breaker in the model. Nonetheless, the memory and speed of the latest computers suits the requirements of such detailed power system models, and recent work has called for an adoption of breaker-oriented models in several aspects of power systems analysis. Specifically, the need for a reference three-phase, breaker-oriented system such as the one proposed in Chapter 7 has arisen from the modeling capabilities of recent computer programs.

4.5.2 State Estimation Applications

State estimation consists of determining the voltage (magnitude and angle) at every bus of an electric network by using a set of redundant measurements. One aspect of the state estimation process is to identify bad measurements (*outliers*) and what caused such measurements to be impaired. Errors on circuit breaker status (breaker status not correctly reported by a relay) affect load flow estimates. Such errors can have consequences in protection schemes when the estimated currents contradict the measurements. Such errors can also make operators think that the operation of a power system in a certain range is possible when some operating limits are, in fact, exceeded.

4.5.2.1 Circuit Breaker Status Error Detection

Circuit breakers that are unexpectedly open or closed cause discrepancies between measurements and the results of state estimation [138, 139, 140]. With erroneous breaker states, state estimation is performed using a wrong system topology. Typical examples involve lines that are unexpectedly disconnected or substations that are split into two entities from an electrical standpoint. In such cases, state estimation is performed on the wrong assumptions that substations are still a single entity or that the disconnected lines are still connected to the system (Figure 18).

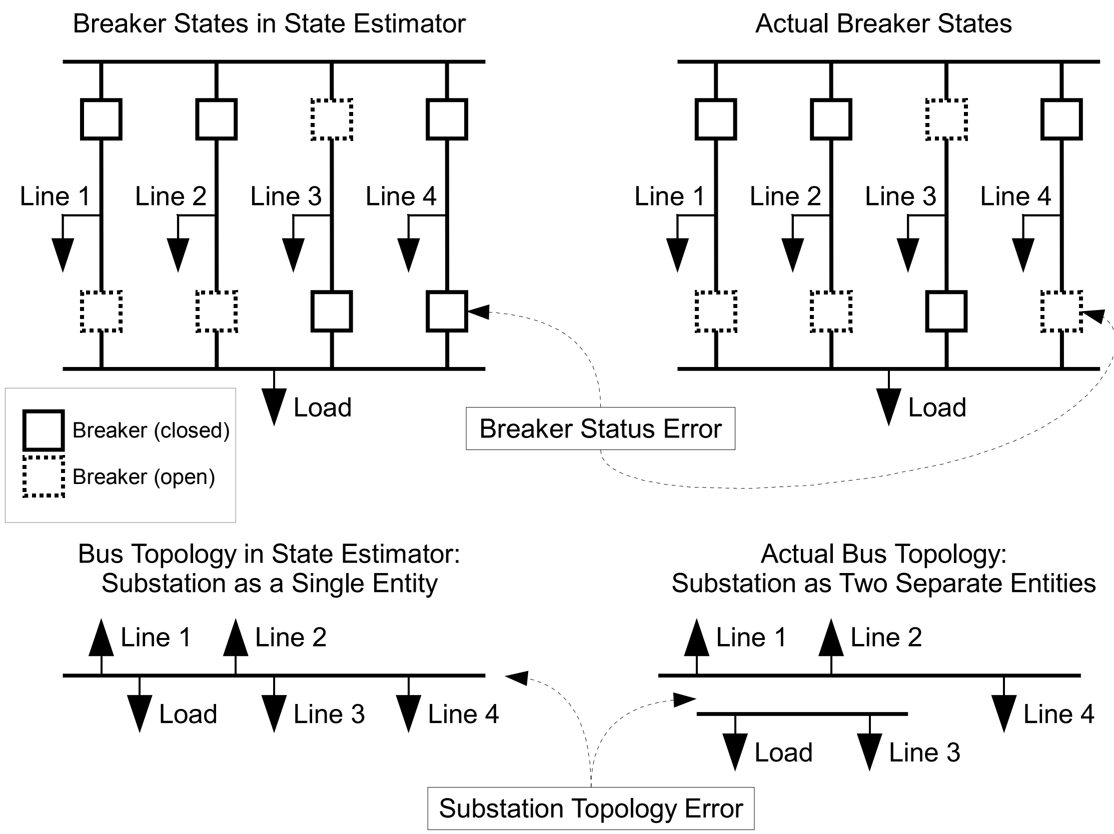


Figure 18: Example of a circuit breaker status error and its implication in substation topology.

The use of the breaker-oriented approach to model substations with frequent measurement errors has been recommended to address circuit breaker status errors. In these recommendations, state estimation is first performed using the bus-oriented models; the breaker-oriented model is applied thereafter to refine the estimated states at selected substations as needed [138, 141, 142]. The proposed breaker-oriented modeling approach may apply to a single substation at a time or to multiple substations together to identify circuit breaker status errors in a systematic fashion.

Wrong assumptions on circuit breaker states cause state estimation errors. These errors demonstrate the inability, by using bus-oriented models, to quantify the impact of different substation topologies on power flow and state estimation. The authors of the cited works show that the detection of breaker status errors can be improved using breaker-oriented substation models. They also note that the lack of circuit breaker monitoring is a factor that increases the incidence of breaker status errors. These errors may be reduced with the monitoring and communications capabilities found in advanced relays and integrated substation computer systems.

4.5.2.2 Explicit Substation Breaker Modeling and the SuperCalibrator Concept

Accuracy is a key aspect of modern power systems models and algorithms. The performance of modern substation automation systems is tied to the precision of the simulated data and the fidelity of the models.

The SuperCalibrator is an accuracy-driven, distributed state estimator that fits GPS-synchronized measurements into a detailed, comprehensive system model. Besides state estimation, the SuperCalibrator facilitates the detection of topology errors and enables distributed alarm processing. This section highlights key facts of the SuperCalibrator concept [143, 23, 144] as relate to applications of explicit breaker arrangement models in substations.

The accuracy of the SuperCalibrator is achieved in several ways. First, the SuperCalibrator concept takes advantage of modern phasor measurement units (PMU) that measure complex voltage and current phasors. Spcifically, each substation must provide at least one GPS-synchronized measurement with a magnitude accuracy of 0.1 % and a time accuracy of 1 μs or 0.02°. The accuracy achieved in GPS clocks allows the synchronization of all phasors to the same time reference before performing state estimation. Second, the measurements are fit into a detailed, realistic model of the system that is three-phase, based on physical parameters of the devices, and that models substation breaker layouts and instrumentation channels explicitly. With such an accurate network model, the systematic errors introduced by asymmetries, switchgear, instrument transformers, and instrumentation cables and be compensated, and the results of state estimation are improved.

For demonstration purposes, a laboratory scaled model of a generator substation has been created [94, 95, 104]. The wiring of the substation model includes instrumentation channels and circuit breakers on all the concerned phase conductors to allow analysis of power system events at the sensor, relay, or circuit breaker level (Figure 19).

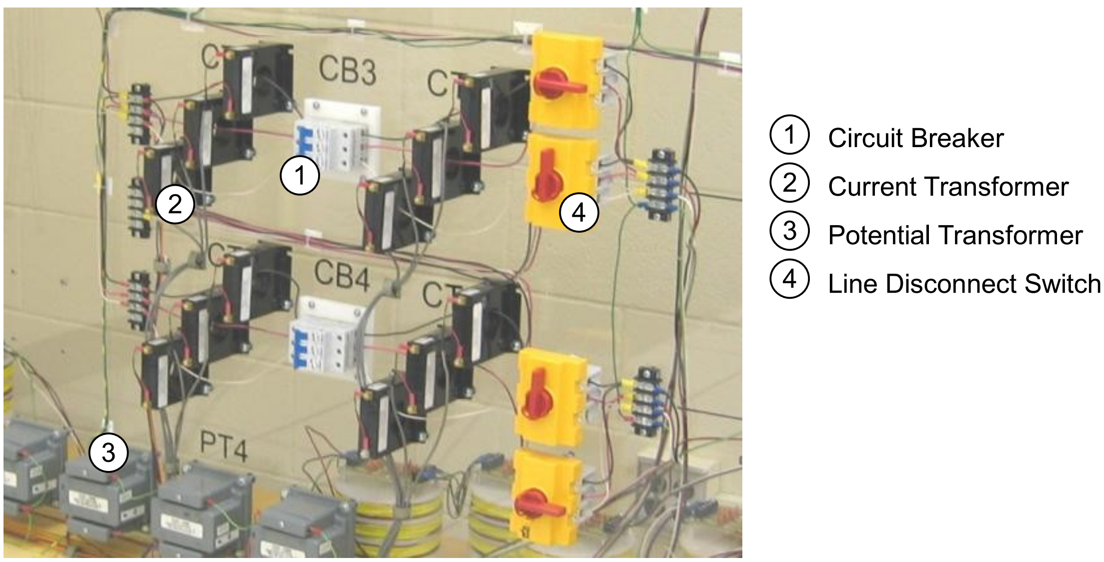


Figure 19: Detail picture of a laboratory scaled model of a substation showing explicit wiring of circuit breakers and instrumentation channels.

Although the explicit modeling of breakers and instrumentation considerably increases the size of the state vector for the entire system, the distributed aspect of the SuperCalibrator reduces the scope of the state estimation to one particular substation and its neighboring buses. As a result, the implementation of distributed state estimators with breaker-oriented substation models is less complex than a centralized state estimator with the same detailed system model.

4.6 Probabilistic Fault Analysis

Because certain substation layouts provide path redundancy, the breakers in such substations must be rated to interrupt the highest fault current on any of the lines connected to that substation [114].

To obtain the stresses imposed to a circuit breaker, probabilistic fault analysis methodologies are preferred to deterministic approaches given (a) the large number of events that otherwise need to be individually considered [145] and (b) the random nature such events [21]. The computation of probabilistic distributions of fault currents in power system components using Monte Carlo simulations is presented in several papers [146, 147] and used in several works related to circuit breaker ratings [148, 149, 150, 151].

One paper [152] also introduces the computation of the risk of breaker failure based on the density of stresses. Specifically, the author of the paper uses the following random parameters to determine circuit breaker reliability data: system conditions, fault location, fault type, and fault duration. The computations of circuit breaker failure and subsequent reliability data are further developed in this thesis.

The Monte Carlo computation of the probability density function (PDF) of fault currents through a breaker follows the algorithm shown in Figure 20. The resulting function is denoted $w(I_F)$ throughout this document. A conceptual graph of such a distribution (density and cumulative probability) is shown in Figure 21. It should be noted that a numerical simulation yields a discretized PDF that utilizes intervals for the different current magnitudes. For theoretical analysis, the continuous form of the same PDF is utilized.

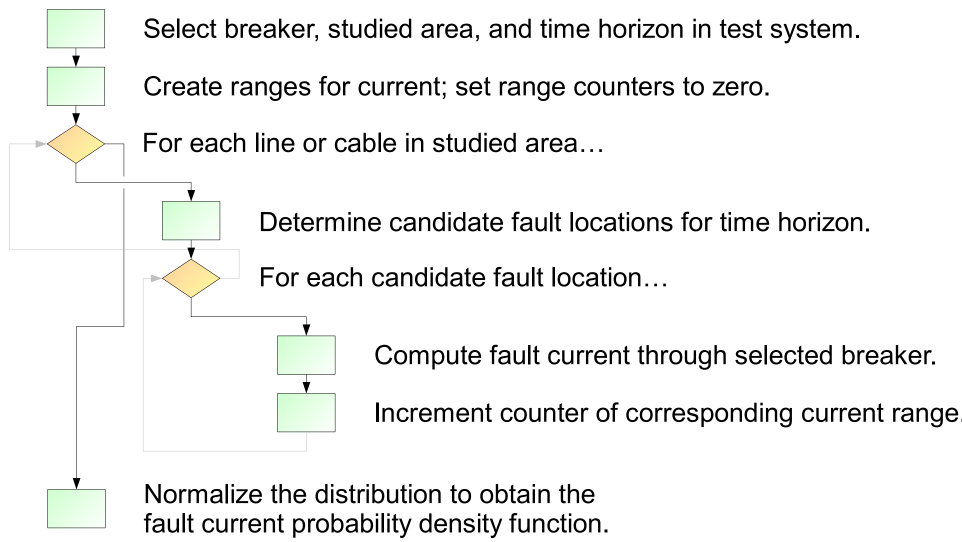


Figure 20: Monte Carlo algorithm for fault current probability density functions.

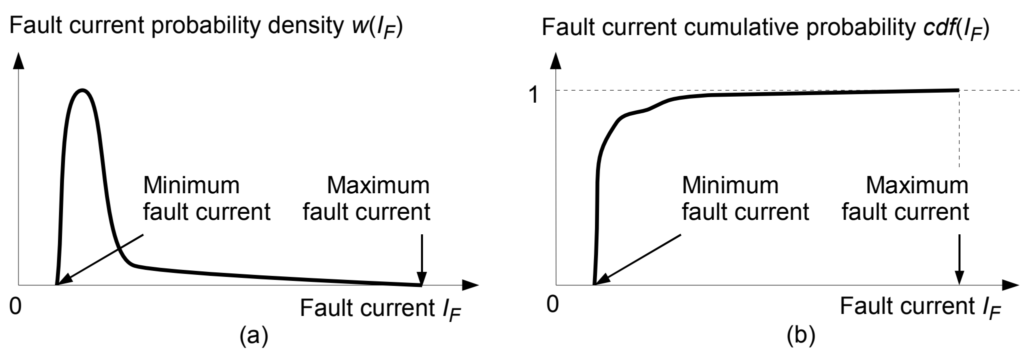


Figure 21: Conceptual graphs of the fault current probability density function (a) and cumulative probability function (b).

The challenges highlighted in the initial publications in terms of computational power no longer exist. Computers nowadays have enough memory for modeling detailed power grids, and parallel computing with the distribution of the simulation effort across several machines [153] is no longer a requirement. Moreover, the computed fault probability density functions have been refined in subsequent papers.

4.7 Contingency Analysis

The failure of a circuit breaker results in outages that affect wide areas as a result of the operation of backup protection. The operation of backup protection schemes exposes backup circuit breakers to stresses that may reduce their lifetime. The loss of two circuit breakers ($N-2$ contingency) or more has more dramatic consequences than the loss of a single breaker because additional customers lose power. Moreover, the failure of the second (backup) breaker is conditioned by the failure of the first breaker. (Backup breakers cannot fail if primary breakers do not fail.) In other words, increased breaker failure probabilities augment the chances for $N-2$ contingencies to occur.

In this study, the consequences of a single breaker failure (an $N-1$ contingency) are analyzed. Advanced contingency selection and ranking methodologies for several common-mode outages are discussed in a thesis recently completed at Georgia Tech [41]. Contingency analysis is also conducted as part of a model for preventive breaker maintenance [121], where several power system events involving breaker failures are analyzed. System reliability is measured with the probability of a load connected at a substation to be disconnected as a result of the failure of the considered breakers.

The circuit breaker reliability model developed in this thesis can be used in contingency analysis. Possible future outcomes of such analyses is an assessment of bulk power system reliability that includes the impact of distributed generation and increased fault currents.

4.8 Summary

In this chapter, existing circuit breaker reliability models and protection practices to preserve circuit breaker reliability are reviewed.

Circuit breaker reliability models have been developed to schedule maintenance based on inspection tests and condition monitoring. In addition, power system reliability assessments have been conducted using contingencies simulated from hypothetical breaker failures.

Because increased fault currents impose additional stresses and wear to circuit breakers, maintenance models should include failures rate contributed by such fault currents. A methodology to obtain the contribution of fault currents to breaker failures is developed in Chapter 5. Elements of the developed methodology such as the Monte Carlo computation of fault statistics and the use of breaker-oriented models (since 1996 in the IEEE 24-bus system) have already been in use, and their importance are reemphasized in this study. The circuit breaker reliability model developed in this thesis includes stress-induced failure rates. The model can be used in assessments of bulk power system reliability that account for the impact of distributed generation and increased fault currents.

Strategies to circumvent circuit breaker overstress (switching, current limiters) have been applied on a case-by-case basis. This includes adapting protection schemes of distribution networks that have distributed generation in service. The philosophy of such strategies is simple and consists of avoiding the operation of breakers if their fault currents exceed their ratings. In Chapter 6, an attempt is made to formulate a general switching strategy for overdutied breakers and to formulate an economic dispatch problem that accounts for circuit breaker failure rate constraints.

CHAPTER V

PROPOSED METHODOLOGY TO PREDICT CIRCUIT BREAKER FAILURES AND LIFETIME

5.1 Overview

Rising fault current levels exceeding breaker ratings contribute to increased circuit breaker failures. Additional breaker failures result in additional power system outages with extended consequences for customers. Therefore, the knowledge of the statistical fault current levels is a pillar to assess circuit breaker adequacy. A methodology to quantify the stress-related breaker failure probability is described in this chapter. A quantitative assessment of circuit breaker reliability helps operating power systems within circuit breaker interrupting capabilities.

In addition to the computation of the probability of failure of a circuit breaker from fault current statistics (PDF), a model of the evolution of the breaker duty over the years as power systems grow and generation capacity increases is proposed. The fault current profile and its evolution over a certain time horizon are combined with a model of the circuit breaker interrupting capability that reflects the interruption history of the breakers. Together, these data are used to compute the evolution of the stress-induced failure probability of the studied breakers on a given time horizon. From the knowledge of the failure probabilities, estimates of the lifetime of the studied breakers are provided.

The theory behind the proposed methodology for circuit breaker failure analysis is described in this chapter. An illustrative application using a 24-substation test system is provided in Chapter 7.

5.2 *Substation Breaker Fault Analysis and Adequacy Assessment*

5.2.1 Principle

Because the current flows through multiple paths inside substation arrangements such as breaker-and-a-half [114] (Figure 14), there are numerous scenarios for circuit breaker fault analysis. Substation breaker fault analysis is possible using the breaker-oriented approach described in Section 4.5.

The analysis of circuit breaker adequacy is the preliminary step to predict stress-induced circuit breaker failures. To assess circuit breaker adequacy, breaker-oriented models are applied in a two-step process: (i) a line flow/fault analysis is performed without the breaker arrangements, and (ii) fault currents contributed by each line are split between the different substation branches and breakers.

5.2.2 Three-Phase Quadratic Power Flow Formulation and Solution

The principle of the quadratic power flow (QPF) is to write all power flow equations as a system of first and second order complex equations. The power balance is derived from Kirchhoff's current law for each phase at each node of the system. The generalized QPF formulation described in this section has two advantages [93]: (i) trigonometric functions are removed without introducing approximations, and (ii) the Newton method converges faster with QPF equations than with Equations (1) and (2).

The equations of device k (a transmission line, transformer, etc) in steady-state operation (single frequency) are written in the following generalized Norton form:

$$\begin{matrix} \text{External equations } \rightarrow \\ \text{Internal equations } \rightarrow \end{matrix} \begin{bmatrix} \widetilde{I}^k \\ 0 \end{bmatrix} = y_{eq}^k \begin{bmatrix} \widetilde{V}^k \\ \widetilde{Y}^k \end{bmatrix} + F\left(\begin{bmatrix} x^{kT} \; f_{eq,1}^k \; x^k \\ x^{kT} \; f_{eq,2}^k \; x^k \\ \vdots \end{bmatrix} \right) - b_{eq}^k. \quad (5)$$

In the equation above, $\widetilde{I}^k$, $\widetilde{V}^k$, and $\widetilde{Y}^k$ are the vectors of terminal currents, terminal voltages, and internal states, respectively. y_{eq}^k, b_{eq}^k, and $f_{eq,1}^k$ are equivalent matrices of the proper size. $F(\bullet)$ denotes a purely real term. The term x^k is defined as

$$x^k = \begin{bmatrix} Re(X^k) & Im(X^k) \end{bmatrix},$$

where the state vector $\widetilde{X}^k$ is

$$\widetilde{X}^k = \begin{bmatrix} \widetilde{V}^k \\ \widetilde{Y}^k \end{bmatrix} \begin{matrix} \leftarrow \text{ External states} \\ \leftarrow \text{ Internal states} \end{matrix} .$$

The network equations consist of the Kirchhoff's current law at each node of the system with connectivity constraints (6) and the internal equations for all devices (7):

$$\sum_{k \in \{\text{devices}\}} A^k \widetilde{I}^k = 0, \tag{6}$$

$$\text{<Internal equations of all devices>} \quad . \tag{7}$$

$\widetilde{I}^k$ contains the terminal currents of device k, composed of the currents at the composite nodes j_1, j_2, etc. $A_{i,j}^k$ is a component incidence matrix, with

$$A_{i,j}^k = \begin{cases} 1 & \text{if terminal } j \text{ of component } k \text{ is connected to node } i, \\ 0 & \text{otherwise.} \end{cases}$$

With $\widetilde{V}$ is the vector of all bus voltages, the terminal voltages of device k are

$$\widetilde{V}^k = (A^k)^T \ \widetilde{V}. \tag{8}$$

Upon substitution of device equations and incidence equations (8), Equations (6) and (7) become quadratic and constitute the network equations (9):

$$\widetilde{Y}\widetilde{X} + F\left(\begin{bmatrix} x^T \ f_1 \ x \\ x^T \ f_2 \ x \\ \vdots \end{bmatrix}\right) - \widetilde{B} = 0, \tag{9}$$

where $\widetilde{X}$ contains all the component states $\widetilde{X}^k$; x is the vector of network states composed of all the component states x^k; $\widetilde{Y}$, f_i, and $\widetilde{B}$ are matrices with appropriate dimensions.

The numerical algorithm for solving Equation (9) consists of two steps. First, the network equations (9) are converted into Cartesian coordinates (real and imaginary parts separated). The procedure is equivalent with replacing each element in $\widetilde{Y}$ with its corresponding 2×2 Hermitian matrix. In particular, $\widetilde{Y}_{i,j}$ is replaced by

$$\begin{bmatrix} Re(\widetilde{Y}_{i,j}) & -Im(\widetilde{Y}_{i,j}) \\ Im(\widetilde{Y}_{i,j}) & Re(\widetilde{Y}_{i,j}) \end{bmatrix}.$$

Then, Equation (9) becomes

$$Re(\widetilde{Y})\; x + \begin{bmatrix} x^T\; f_1\; x \\ x^T\; f_2\; x \\ \vdots \end{bmatrix} - Re(\widetilde{B}) = 0. \tag{10}$$

Equation (10) is solved using Newton's method:

$$x_{n+1} = x_n - J^{-1} \left\{ Re(\widetilde{Y})\; x_n + \begin{bmatrix} x_n^T\; f_1\; x_n \\ x_n^T\; f_2\; x_n \\ \vdots \end{bmatrix} - Re(\widetilde{B}) \right\}, \tag{11}$$

where x_n denotes the state vector at the n^{th} iteration, and J is the Jacobian matrix:

$$J = Re(\widetilde{Y}) + \begin{bmatrix} x_n^T(f_1 + f_1^T) \\ x_n^T(f_2 + f_2^T) \\ \vdots \end{bmatrix}.$$

The convergence of the QPF algorithm is guaranteed because it is the application of Newton's method to a set of quadratic equations. In practice, the algorithm summarized as Equation (11) converges in two or three iterations.

5.2.3 Breaker-Oriented Fault Analysis

Fault analyses in bus and breaker-oriented models start with the solution of a network flow problem that corresponds to normal operation. Equation (11) is solved without the breaker arrangements. The solution to this network flow serves as the initial condition for the currents through all transmission lines.

When a fault is introduced, the network model is linearized around the operating point immediately preceding the fault. With this linearization, the power flow and currents through each transmission line of the faulted system are obtained from pre-fault conditions in a single iteration. The assumption that generator rotor angles remain constant for the expected duration of the fault makes this linearization possible.

The topology of the considered substation is used in the second step of the substation breaker fault analysis. The current contributed by the generators and transmission lines connected at the substation is split into each branch of the substation. The current flowing through each substation breaker is determined using the principle of the current divider and the internal resistance of each branch of the substation.

Because the proposed fault analysis is based on a power flow solution, the computed fault currents correspond to "steady-state" currents if fault conditions were to persist indefinitely. Specifically, transients are not considered in this process, and a separate analysis is necessary to account for transients. In particular, the DC offset dynamics described in Section 2.5 has to be superimposed to the "steady-state" fault currents.

5.3 Determination of Statistical Breaker Stresses

Statistical stresses are the key to quantifying the probability of failure and subsequent reliability indices of overdutied circuit breakers. Statistical stresses are formalized using a probability density function (PDF) of fault currents for each studied breaker. The fault current PDF is accurately computed according to the algorithm shown in Figure 20 in Chapter 4 using the three-phase, breaker-oriented model equations presented in Section 5.2.

The statistical distribution of fault currents depends on the substation topology used and the frequency of usage. The computation of the statistical breaker stresses consists of two parts:

1. For a specific combination of open/closed breakers in a substation (the connectivity state), the expected levels of fault currents are determined.

2. The stresses are combined into a single data set using weight factors. Substation topologies the most often used receive a high weight.

5.3.1 Initial Approach

The first approach consists of collecting the values of fault currents through the studied breaker for faults simulated throughout an entire test system. Only single line faults are considered in this initial approach.

Faults are distributed uniformly on each transmission lines of the studied system. The number of faults simulated is determined by (i) the desired resolution of the fault statistics and (ii) by the number of faults that historically occur per 100 miles of transmission lines per year. Faults at buses are also considered to cover limit cases of fault current levels.

The resulting fault current PDF maps each RMS value of fault currents to a density of probability for such current to flow through the studied breaker, considering faults in the entire system.

5.3.2 Impact of Fault Distance to the Considered Breaker

Routine business would be hampered if all relays and breakers operated every time there is a fault anywhere in a network. To prevent that, relays respond within a designated time frame to faults located in designated protection zones only (Figure 10). The task and stress of clearing faults outside of these protection zones is transferred to other breakers.

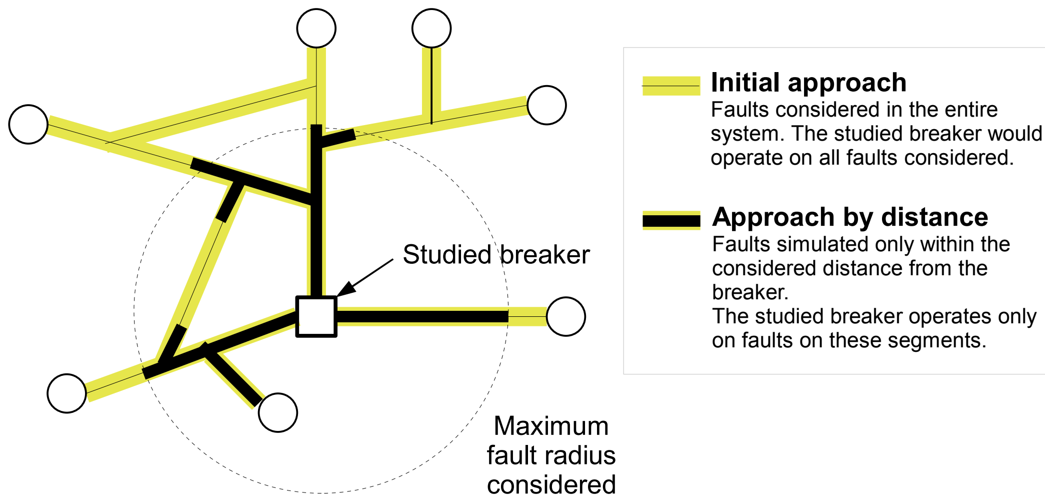


Figure 22: Selection of fault location: initial approach vs. faults within distance from the studied breaker.

Introducing a fault radius from a breaker sets the focus to faults that are within the operating range of that breaker and discards faults beyond the considered radius (Figure 22). A fault radius typically covers all protection zone 1 of a breaker and may overlap with the primary protection zone of other breakers, especially in conservative cases. The radius can be defined as a geographical distance or as an electrical distance (length of transmission lines or equivalent impedances) from the breaker to analyze.

Faults in the first protection zone of a breaker typically draw more current than faults affecting lines not directly protected by the breaker. By focusing on Zone 1 faults that are more likely to contribute to breaker failure, the accuracy of fault current statistics and the failure data of the studied breaker can be improved. In particular, the probability density of high fault currents increases in the $w(I_F)$ distribution. As the fault distance is restricted, the relative weight of high fault currents increases. The accuracy of the $w(I_F)$ distribution can be improved by fine-tuning the fault radius as a simulation factor.

5.3.3 Faults by type

Line-to-ground, line-to-line, and three-phase faults do not occur with the same probability. Single-phase faults are the most common, representing 80 % of the faults or more [149]. An example of the relative frequencies of each type of faults is shown in Table 5. The accuracy of the distribution of fault currents depends on how close the relative statistical frequencies of the simulated faults are from reality.

To evaluate the effect of each type of fault on the breaker fault currents, a normalized fault current PDF $w_i'(I_F)$ is computed for the studied breaker and for each type of fault $i = 1, \ldots, n_T$, where n_T is the number of the types of faults considered. Each of these distributions is assigned the probability factor $b_i \geq 0$ from Table 5 of the corresponding type of fault, with

$$\sum_{i=1}^{n_T} b_i = 1.$$

Since all PDFs $w_i'(I_F)$ are normalized, the weighted sum

$$\sum_{i=1}^{n_T} b_i w_i'(I_F)$$

is also a normalized PDF. This weighted sum is precisely the fault current PDF that accounts for all types of faults (Figure 23). Moreover, since the individual fault current distributions for each type of faults are readily available, they are computed only once, and the analysis translates into applying different weights to these distributions. A set of results using different probabilities for each type of faults can be quickly generated using this procedure.

Differences in statistical fault currents may vary when considering only one versus several types of faults in the same test system. Such differences may affect subsequent circuit breaker reliability indices.

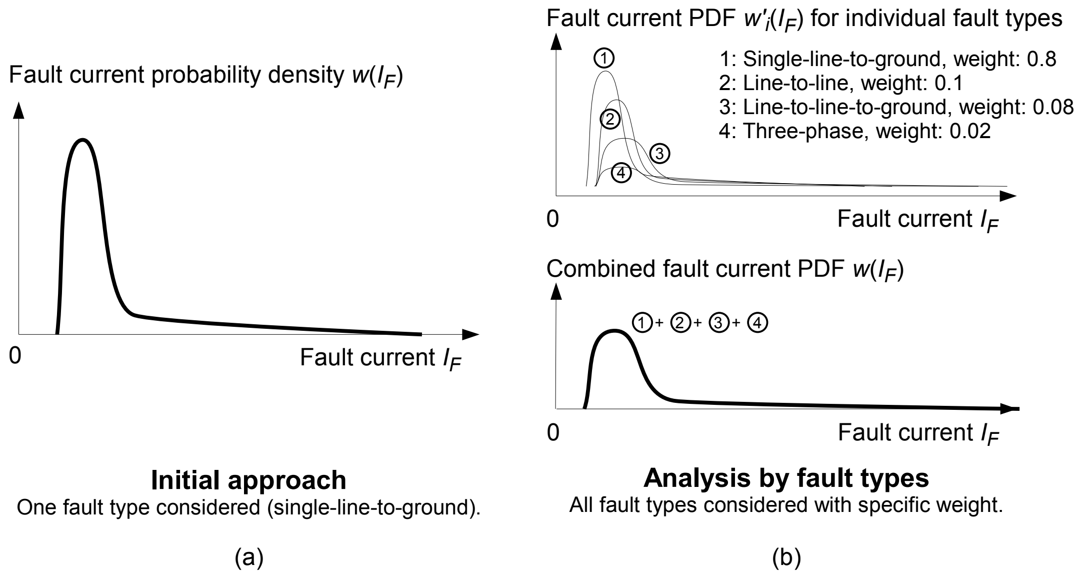


Figure 23: Breaker fault PDFs: initial approach (a) vs. analysis by fault types (b).

5.3.4 Network and Substation Connectivity

The connectivity of the network and the substations (i.e. the set of lines and bus bars that determine the possible connections in the system) determines the equivalent impedance of the system seen from the fault location, and thus, it determines the magnitude of fault currents. The connectivity factor is discussed assuming that the number of generators in service remains the same.

In general, the higher the number of paths between two points of a substation, the lower the fault levels through the breakers within each path. It results that substation topologies are built as a compromise to provide path redundancy between two substation points (for reliability) and keep construction costs acceptable.

5.4 Stress-Induced Breaker Failure Rates

The objective of this section is to estimate the breaker failure rate contributed by the stress caused by intense fault currents. The stress-induced failure rates are obtained using the fault current PDF described in Section 4.6 and using a postulated model of breaker failure probabilities as a function of the current interrupted.

5.4.1 Circuit Breaker Operating Current Threshold

The graph of Figure 21 illustrates a PDF of fault currents through a circuit breaker for faults located throughout the considered system. Because all fault currents are included regardless of fault location, this PDF is unconditional and cannot be used as such to compute breaker failure rates. Otherwise, the given breaker operates for every fault simulated to build the PDF, and that is clearly not the case.

An operating current threshold I_{Op} is introduced to help identify faults associated with the operation of a given breaker. Whenever fault currents above I_{Op} are detected in a circuit, the corresponding breaker is triggered. I_{Op} reflects the settings of protective relays that may trigger the studied breaker. I_{Op} is assumed constant since the minimum relay settings do not change.

A conditional probability density function $w_{Op}(I_F)$ is obtained from $w(I_F)$ by removing current magnitudes below I_{Op} and by normalizing the rest of the density function (Figure 24). It is important to note that $w_{Op}(I_F)$ provides the probability of direct stresses for the studied breaker:

$$w_{Op}(I_F) = \begin{cases} \dfrac{w(I_F)}{\displaystyle\int_{I_{Op}}^{+\infty} w(I)\,\mathrm{d}I} & \text{if } I_F \geq I_{Op}, \\ 0 & \text{otherwise.} \end{cases} \tag{12}$$

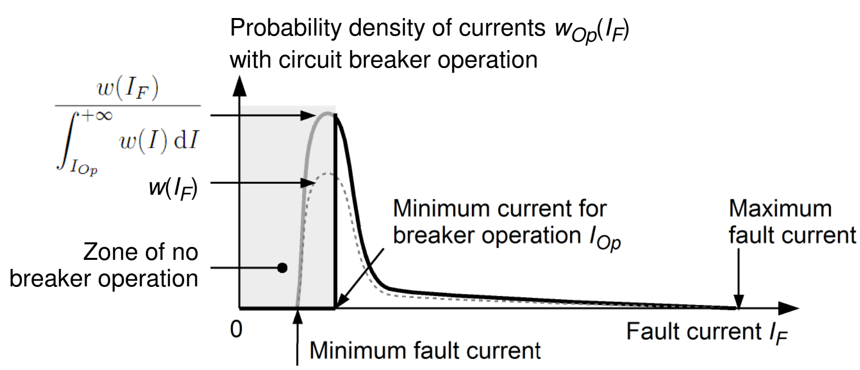


Figure 24: Conditional PDF of fault currents (condition: breaker operated).

5.4.2 Interrupting Failure Function

An interruption failure function $p_F(I_F)$ for each breaker is postulated; the function provides the probability of a breaker failure for each value of the fault current I_F through the breaker at the time of operation (Figure 25). Low fault currents (Zone 1) do not contribute to breaker failure as opposed to high fault currents (Zone 2) that always cause breaker failure. Also, between the two zones is a transition region where the failure probability gradually increases with the current. This transition region is delimited with the currents I_0 and I_1, which are the low and high failure thresholds, respectively. It is assumed that the rated current I_N, I_0, and I_1 when the breaker is in new condition can be determined using manufacturer data. The analytical expression of the postulated interrupting failure function is

$$P_F(I_F) = \begin{cases} 0 & \text{if } I_F < I_0, \\ \dfrac{I_F - I_0}{I_1 - I_0} & \text{if } I_0 \leq I_F \leq I_1, \\ 1 & \text{if } I_F > I_1. \end{cases} \tag{13}$$

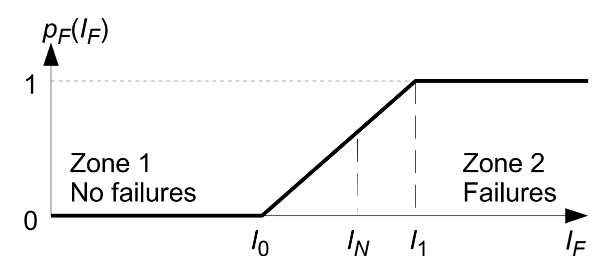


Figure 25: Curve for the postulated breaker interruption failure function.

5.4.3 Stress-Induced Failure Rate

The breaker failure rate is determined from an estimation of the stress-induced probability of circuit breaker failure. This probability is computed by first multiplying the curves shown in Figures 24 and 25. This intermediate product, $w_{Op}(I_F) \times P_F(I_F)$, holds under the condition of breaker operation. Therefore, the stress-induced probability of breaker failure is obtained by multiplying the product between the two curves with the probability of breaker operation.

The probability of breaker operation is the probability that a fault occurs, such that the current I_F through the studied breaker causes that breaker to operate ($w_{Op}(I_F) \neq 0$). This probability and the subsequent failure rate computations are tied to a given time frame, one year for instance. Assuming n_F faults were simulated to obtain the $w(I_F)$ and $w_{Op}(I_F)$ distributions over the given time frame, the corresponding number of breaker operations is

$$n_{Op} = n_F \int_{I_{Op}}^{+\infty} w(I_F)\,\mathrm{d}I_F. \tag{14}$$

The n_F faults simulated do not necessarily have to be uniformly distributed within the system transmission paths. Some lines may have a higher fault rate than others, and this fact is already accounted for in the current distribution.

The number of faults n_F and number of breaker operations n_{Op} being statistical numbers (e.g. number of breaker operations per year), the probability of breaker operation is computed from a Poisson distribution with parameter $\lambda = n_{Op}$. If X denotes the number of breaker operations (a random variable) in the given time frame, the general expression of the probability for n operations to occur during the same time frame is

$$P(X = n) = \frac{\lambda^n e^{-\lambda}}{n!}, \tag{15}$$

with $X \geq 0$ and $n \geq 0$.

The desired probability of breaker operation is complementary to the probability of no breaker operation:

$$\begin{aligned} P(X = 0) &= \frac{\lambda^0 e^{-\lambda}}{0!} = e^{-\lambda} = e^{-n_{Op}}, \\ P(X > 0) &= 1 - P(X = 0) = 1 - e^{-n_{Op}}. \end{aligned} \tag{16}$$

Finally, the stress-induced failure probability for the given time frame is

$$P_{Stress} = \left(1 - e^{-n_{Op}}\right) \int_0^{+\infty} w_{Op}(I_F) \times P_F(I_F)\,\mathrm{d}I_F. \tag{17}$$

The stress-induced failure rate is then obtained, again assuming that breaker failures obey a Poisson process:

$$\begin{aligned} P_{Stress} &= \left(1 - e^{-\lambda_{Stress}}\right) \\ \lambda_{Stress} &= -\ln(1 - P_{Stress}) \end{aligned} \tag{18}$$

5.5 *Impact of Generation Capacity Growth*

Fault currents through a circuit breaker evolve with time. The growth of power systems is one cause of increased circuit breaker failures because generation capacity growth directly contributes to increases of fault currents and stresses. As a result, the evolution of the fault current PDF is modeled with a postulated pattern of generation capacity growth over the studied time horizon.

5.5.1 Generation Capacity Growth Model

Additions to the generating capacity occur at discrete times that correspond to the commissioning of new utility plants, independently-owned generators, and distributed generation. As a result, the planning horizon (ten, twenty, thirty years) is separated into a number of time intervals, for example one-year intervals. The generation capacity increases at the end of each interval. This time discretization is arbitrary and can be coarser or finer as needed. The probability density functions of expected fault currents through each breaker are re-evaluated with the expected generating capacity when entering a new time interval.

Assuming a time horizon $[t_0, t_{max}]$, increases in generation capacity occur at times t_1, t_2, $\ldots$, t_n, with $t_0 \leq t_i \leq t_{max}$ and $t_{i-1} < t_i$ for all $1 \leq i \leq n$. For each of these times, the expected increase in capacity is Δc_1, Δc_2, $\ldots$, Δc_n, with $\Delta c_i > 0$ for all i. The sum of the discrete increases is the overall projected growth Δc of the installed generation capacity over the time horizon. If the initial installed capacity is c_0, the ending generation capacity is $c_0 + \Delta c$. For example, if the overall growth of installed generation in a country is 5 % over $t_{max} - t_0 = 10$ years, one would write $\Delta c/c_0 = 5\%$. The discretized generation growth pattern described is illustrated in Figure 26.

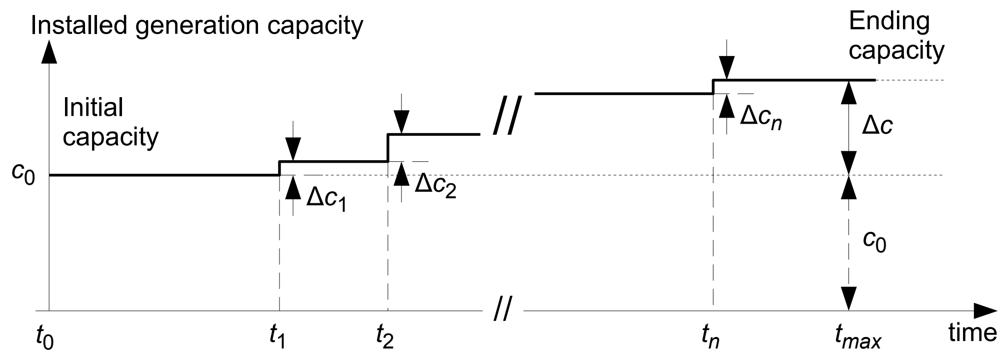


Figure 26: Postulated generation growth pattern.

5.5.2 Increase in Circuit Breaker Fault Currents

The statistical PDF of stresses $w(I_F)$ introduced in Chapter 4 maps the probability density of fault currents I_F for a given breaker. The PDF of stresses is recomputed every time the generation capacity of the system increases and every time the topology of the system changes. The result is a set of PDFs $w[t_i](I_F), 1 \leq i \leq n$ that represent the statistical evolution of the duty of the studied breaker over the chosen time horizon. (The notation $x[t_i](\bullet)$ denotes the form taken by the variable or function $x(\bullet)$ during time interval $[t_i, t_{i+1}]$.)

In the absence of historical data, the evolution of the PDF of interrupted currents can be estimated theoretically by mapping fault currents at time t_i to their expected value between t_{i+1} and t_{i+2}, assuming an average growth rate of $\Delta c_{i+1}/c_i$:

$$I_F[t_{i+1}] = I_F[t_i] \left(1 + \frac{\Delta c_{i+1}}{c_i}\right). \tag{19}$$

The PDF of fault currents at time t_{i+1} is thus

$$w[t_{i+1}](I_F) = w[t_i] \left(\frac{I_F}{1 + \frac{\Delta c_{i+1}}{c_i}}\right). \tag{20}$$

The estimate above is not unreasonable if distributed generation is expected to grow uniformly throughout the system as more customers adopt power suppliers outside of conventional large-scale utility plants.

5.5.3 Estimation of the Cumulative Current Interrupted and the Number of Operations

The interrupting failure function above also varies depending on the history of interruptions. Specifically, the failure thresholds I_0 and I_1 of the interrupting failure function change with the cumulative current interrupted and the number of interruptions. (Typical recommendations can be found in IEEE standards C37.04 [37] and C37.06 [154].)

Past operations of a breaker, including the levels of currents interrupted, are assumed recorded by the owning utility. The expected number of future operations of the same breaker is determined from an estimate of the number of faults per year n_F corresponding to the simulated current PDF divided by the scaling factor to obtain the conditional PDF shown in Figure 24. Specifically, the expected number of future operations $n_{Op}[t_i]$ in the time interval $[t_i, t_{i+1}]$ is

$$n_{Op}[t_i] = n_F(t_{i+1} - t_i) \int_{I_{Op}}^{+\infty} w[t_i](I_F)\,\mathrm{d}I_F. \tag{21}$$

The total average current interrupted $I_{Op}[t_i]$ in the time interval $[t_i, t_{i+1}]$ is obtained by multiplying the number of operations during that time, $n_{Op}[t_i]$, with the average RMS value of currents interrupted by the breaker in the same time interval:

$$I_{Op}[t_i] = n_{Op}[t_i] \int_{0}^{+\infty} w_{Op}[t_i](I_F)\,\mathrm{d}I_F. \tag{22}$$

The breaker cumulated duty at time $t \in [t_i, t_{i+1}]$ is estimated from the number of operations of the considered breaker:

$$I_{Cumul}(t) = I_{Cumul}(t_i) + \left\lfloor \frac{t - t_i}{t_{i+1} - t_i} n_{Op}[t_i] \right\rfloor I_{Op}[t_i]. \tag{23}$$

(The half brackets denote the integer part of the enclosed expression.)

The recursive expression above can be converted into a closed-form expression, for $t \in [t_i, t_{i+1}]$, again:

$$I_{Cumul}(t) = I_{Cumul}(t_0) + \sum_{j=0}^{i-1} I_{Op}[t_j] + \left\lfloor \frac{t - t_i}{t_{i+1} - t_i} n_{Op}[t_i] \right\rfloor I_{Op}[t_i], \tag{24}$$

where $I_{Cumul}(t_0)$ is the cumulated duty of the considered breaker at the beginning of the studied time horizon. The cumulated duty of the considered breaker at t_0 depends on the breaker interruption and maintenance history.

5.5.4 Degradation of Breaker Interrupting Capabilities with Time

Two failure threshold currents I_0 and I_1 are defined in Section 5.4.1. The interrupting capability of a circuit breaker tends to decrease as the number of operations and the cumulated duty increase. In other terms, I_0 and I_1 decrease from one time interval $[t_i, t_{i+1}]$ to the next.

There are many ways to model the degradation of the interrupting capability of circuit breakers. In this study, the upper failure threshold current I_1 declines to 90 % of its original value when the cumulated duty reaches 8 times the breaker rating; the lower threshold current I_0 is 75 % of the upper threshold:

$$I_1(t) = I_1(t_0)\left(1 - 0.1\frac{I_{Cumul}(t)}{I_{Std}}\right), \tag{25}$$

$$I_0(t) = 0.75\ I_1(t), \tag{26}$$

where I_{Std} is the standard cumulated duty of the breaker before heavy maintenance or replacement is needed, as recommended in IEEE Standard C37.04 [37] for example.

For each time interval $[t_i, t_{i+1}]$, the probability and rate of breaker failure are computed using Equations (17) and (18) with the indexed quantities $n_{Op}[t_i]$, $w_{Op}[t_i](I_F)$, and $P_F[t_i](I_F)$.

5.6 *Circuit Breaker Reliability and Time-to-Failure Model*

5.6.1 Per-Component State Space and State Probabilities

The proposed circuit breaker reliability model is built from the combination of the reliability models of its individual components. As already stated in Section 3.2.5.1, the individual breaker components focus on specific functional aspects of the device. The selection of the functional components varies from one study to the other [119, 120] depending on the particular needs of these studies. In this study, breakers have four functional elements listed in Table 12. Examples of failure modes for each component are also shown in the table.

Table 12: Breaker components and examples of component failure modes

Component	Index	Failure Modes
Relay	R	Failure to detect or respond to fault conditions Failure to send trip signals to breakers
Trip Mechanism	T	Failure to initiate plate separation; issues with trip coil
Mechanical Support	M	Failure to fully open the contacts at desired speed e.g. bad grease, obstacles in plate motion, broken arms, etc.
Base Plates	P	Failure to interrupt the arc, dielectric failure, or plates fail to separate (welding)

5.6.1.1 *State Spaces and Transitions*

Each breaker component X has its own failure rate $\lambda_X(t)$ and a constant repair rate μ_X. The performance of the circuit breaker as a whole depends on whether its components are functionally operational or not, with respective probabilities $p_X(t)$ and $q_X(t)$. The functional and failed state probabilities satisfy

$$q_X(t) = 1 - p_X(t)$$

$$0 \leq p_X(t) \leq 1$$

$$0 \leq q_X(t) \leq 1.$$

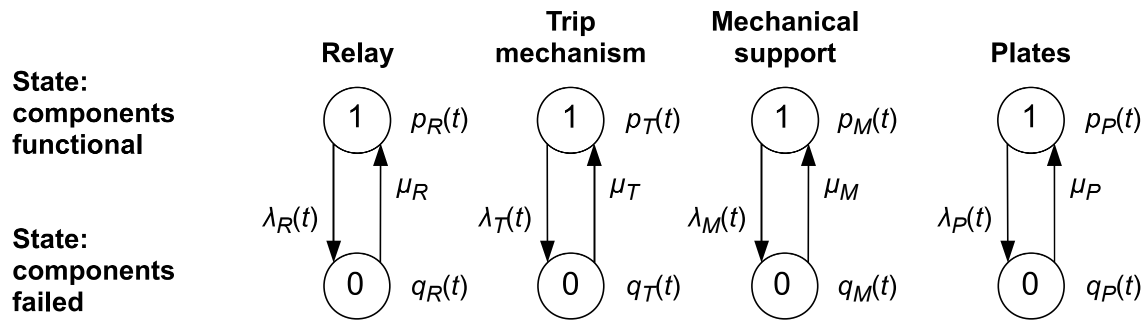


Figure 27: Illustration of the functional states of each breaker component.

For each breaker component, the transitions between the functional state and the failed state can be modeled as independent, continuous-time Markov chains (Figure 27). Transitions from the operational to the failed states are denoted in the figure by arrows with the corresponding failure rate. An exponential model is used under the assumption that failures occur independently of previous failures and repairs.

Assuming that only the breaker plates must endure fault interruption, the failure rate of the plates has an additional term compared to other breaker components, which is the stress-induced failure rate λ_{Stress} obtained from Equation (18).

5.6.1.2 Per-Component State Probabilities

The simultaneous failure of two or more breaker components is excluded as components have independent failure modes. Assuming only one component fails at a time, the state probabilities for each individual component are obtained from basic continuous-time Markov chain theory. The differential equations that govern the transitions from the operational to the failed state of each component are

$$\frac{\mathrm{d}p_X}{\mathrm{d}t} = -\lambda_X(t)p_X(t) + \mu_X q_X(t), \tag{27}$$

$$\frac{\mathrm{d}q_X}{\mathrm{d}t} = \lambda_X(t)p_X(t) - \mu_X q_X(t). \tag{28}$$

The initial conditions represent a fully operational breaker:

$$p_X(0) = 1 \quad \text{and} \quad q_X(0) = 0. \tag{29}$$

Assuming λ_X remains constant during a certain time period, the solution to the differential equations above gives the probabilities of being in the operational state or being the in the failed state for each individual breaker component:

$$p_X(t) = \frac{\lambda_X}{\lambda_X + \mu_X}\left(\frac{\mu_X}{\lambda_X} + e^{-(\lambda_X+\mu_X)t}\right), \quad (30)$$

$$q_X(t) = \frac{\lambda_X}{\lambda_X + \mu_X}\left(1 - e^{-(\lambda_X+\mu_X)t}\right), \quad (31)$$

with t being counted from the beginning of the considered time horizon. Long-run probabilities with constant failure and repair rates are

$$p_X(\infty) = \frac{\mu_X}{\lambda_X + \mu_X} \quad \text{and} \quad q_X(\infty) = \frac{\lambda_X}{\lambda_X + \mu_X}. \quad (32)$$

5.6.2 Aging Factor

All breaker components are subject to aging. The aging failure rates are different for each component. Many gradual failures described in [59] are aging-related failures or hidden failures that become apparent as a result of an aging process.

One way to model the evolution of aging-related failure rates is through the well-known "bathtub" equations. Bathtub failure rates with respect to time can be generated using a sum of three Weibull functions:

$$\lambda_{X,aging}(t) = \sum_{i=1}^{3} \alpha_i \lambda_X^a (\lambda_X^a t)^{\alpha_i - 1} \quad (33)$$

with $\alpha_1 < 1$, $\alpha_2 = 1$, and $\alpha_3 > 1$. The subscript X denotes one of the four breaker components enumerated in Figure 29. The constants λ_X^a for each device are assumed known from the reliability data from the relay and breaker manufacturers.

5.6.3 Circuit Breaker State Space

Assuming each of the four components of the breaker operates and fails independently, there are 16 possible Markov states for each breaker. All possible transitions between the 16 states involving the failure or repair of a single component are shown in Figure 28. Each direction and type of line in Figure 28 corresponds to a change of state of the same component. For instance, vertical lines always correspond to failures or repairs of the trip mechanism; transitions 1-2, 3-4, 5-6, 7-8, etc. involve the relay. Each state is identified by a number that is used in Table 13 to identify which components of the breaker are operational and which components have failed.

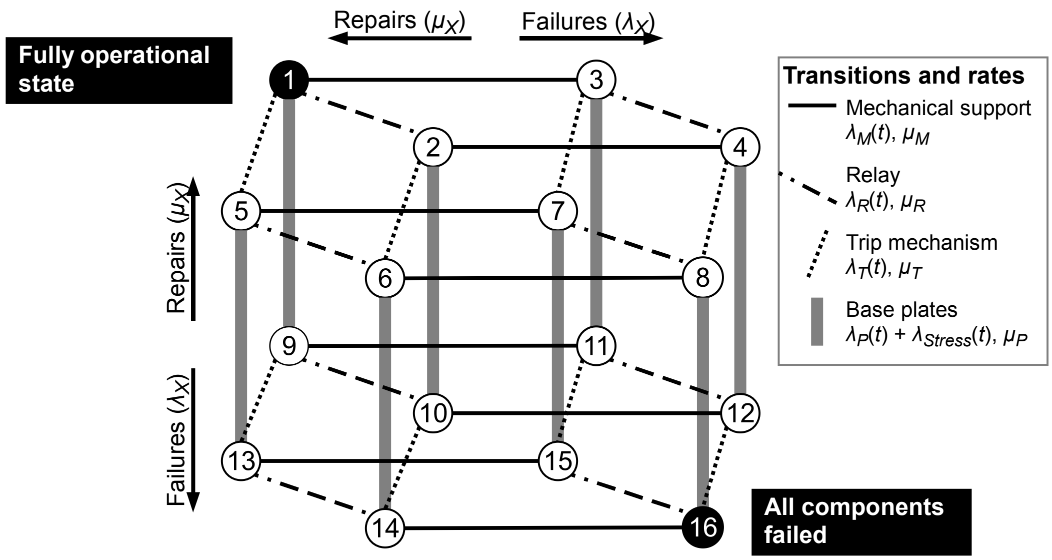


Figure 28: Circuit breaker state space showing failure or repair transitions involving a single component only.

Table 13: Breaker state enumeration and incidence matrix. Marks indicate a failed component.

State	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Relay		!		!		!		!		!		!		!		!
Mechanical			!	!			!	!			!	!			!	!
Trip					!	!	!	!					!	!	!	!
Plates									!	!	!	!	!	!	!	!

Because the breaker components fail independently, the probability to be in each breaker state is the product of the corresponding state probabilities of each component. For example, in state number 4, the plates and the trip mechanism are operational, but the mechanical support and the relay link have failed. Therefore, the probability for this state is

$$p_4(t) = p_P(t) \times p_T(t) \times q_M(t) \times q_R(t) = p_P(t) \times p_T(t) \times (1 - p_M(t)) \times (1 - p_R(t)). \quad (34)$$

Only one state with all components functional (State 1 in Table 13) represents the breaker in good operating condition. All other states (States 2 to 16) have at least one component failed. All the components listed in Table 12 are necessary for breaker operation, and fault interruption cannot be completed if any of the breaker components is not operational. As a result, all breaker components are said to be in series in the reliability block diagram [155] (Figure 29).

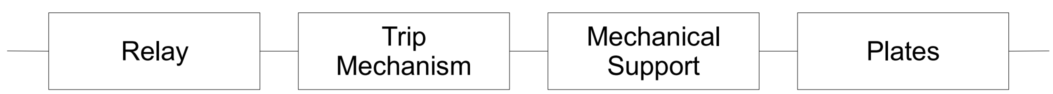


Figure 29: Series reliability block diagram of circuit breaker components.

As a result of using a series reliability diagram, the circuit breaker Markov model used in this study is reduced to two states shown in Figure 30. The combined failure and repair rate of the breaker is the sum of the failure rates of the individual components:

$$\lambda_{CB}(t) = \lambda_R(t) + \lambda_T(t) + \lambda_M(t) + \underbrace{\lambda_P(t)}_{\lambda_{P,aging}(t)+\lambda_{Stress}(t)}. \quad (35)$$

$$\mu_{CB} = \mu_R + \mu_T + \mu_M + \mu_P. \quad (36)$$

Using the simplified two-state Markov chain and assuming the failure and repair rates remain constant during a certain time horizon, the estimated probability of a breaker failure is computed using Equation (32):

$$q_{CB}(\infty) = \frac{\lambda_{CB}}{\lambda_{CB} + \mu_{CB}}. \quad (37)$$

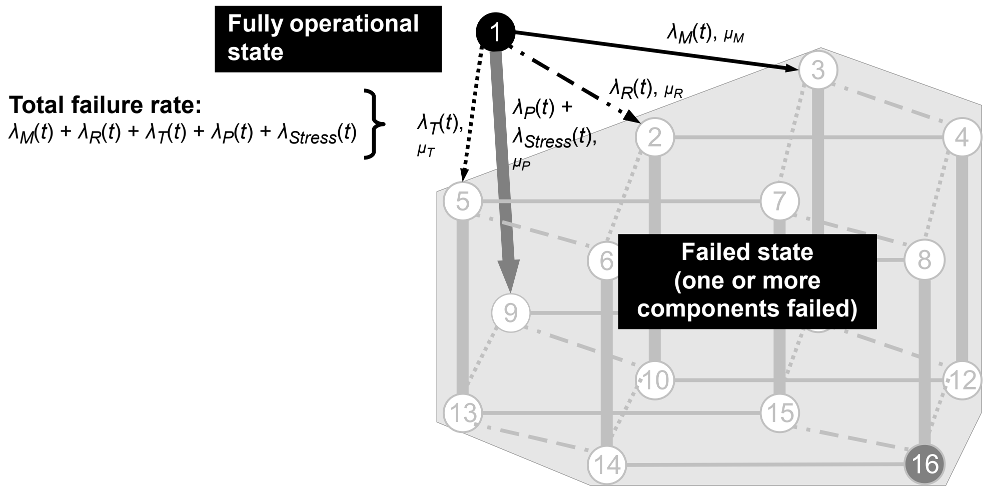


Figure 30: Simplified circuit breaker two-state space with an operating and a failed state.

5.6.4 Estimation of Circuit Breaker Time-to-Failure

The failure rate from the working state to the failed state of the breaker is the sum of the failure rates of the individual components:

$$\lambda_{CB}(t) = \lambda_R(t) + \lambda_T(t) + \lambda_M(t) + \underbrace{\lambda_P(t)}_{\lambda_{P,aging}(t)+\lambda_{Stress}(t)}. \tag{38}$$

With the knowledge of the failure rate as a function of time, the PDF of the time-to-failure can be computed [155] and is given by

$$f_{MTTF}(t) = \lambda_{CB}(t)\ \exp\left(-\int_0^t \lambda_{CB}(\tau)\,\mathrm{d}\tau\right). \tag{39}$$

The equation above provides the density of probability of the MTTF of the considered breaker from the present time. The PDF of the MTTF accounts for the expected growth of the power system under a scenario such as the one outlined in Section 5.5. In particular, the expected MTTF can be obtained from this distribution by taking the mean value of the distribution using

$$MTTF_{Est.} = \int_0^{+\infty} t \times f_{MTTF}(t)\,\mathrm{d}t, \text{ or} \tag{40}$$

$$MTTF_{Est.} = t_M, \text{ with } t_M \text{ such that } \int_0^{t_M} f_{MTTF}(t)\,\mathrm{d}t = \frac{1}{2}. \tag{41}$$

5.7 Summary

With the expansion of power systems with new power plants and distributed generation, the issue of circuit breaker overstress arises when fault currents exceed the ratings of a number of breakers. Overstressed breakers are more likely to fail than breakers that are not overstressed.

The focus of this chapter is on a methodology to quantify the stress-induced probability of breaker failures, or the risk that a breaker fails while opening currents in excess of its rating. The proposed methodology has two highlights: a three-phase, breaker-oriented fault analysis methodology to compute a fault current PDF through all the breakers in a test system, and a procedure to determine a stress-induced breaker failure rate from the fault current PDF. A theoretical account for the growth of generation capacity is also given since circuit breaker adequacy issues have come from system expansion to accommodate a growing demand for electricity.

A circuit breaker time-to-failure model is proposed that combines the stress-induced breaker failure probability with other failure rates (aging) into a Markov model. The time-to-failure model is determined over a time horizon to account for the expansion of power systems.

A numerical application of the concepts outlined so far is presented in Chapter 7.

With a quantified knowledge of circuit breaker stresses and stress-related failures, breaker upgrades and replacements can be targeted to devices with the highest failure probability. Because of budgets, system operating constraints, and manufacturer performance, breaker replacements and upgrades take a certain time during which the system must be operated at a set reliability level. To maintain such a reliability level, there are operational constraints to consider; in addition, actions can be taken to circumvent circuit breaker overstress until the breaker replacement process is complete. Chapter 6 is devoted to new operational constraints and remedial actions to keep circuit breakers within their operating limits.

CHAPTER VI

IMPLICATIONS OF CIRCUIT BREAKER RELIABILITY IN POWER SYSTEMS OPERATION

6.1 Overview

Power system operations and protection must continue at an acceptable reliability level between the time a breaker is "diagnosed" with overstress problems and the time the breaker is upgraded or replaced. Identifying circuit breakers as overstressed increases the number of devices that utilities must plan to replace. Circuit breaker replacements are usually dictated by the capital (infrastructure) investment plans of the utilities. Capital improvement plans apply to only a small fraction of the equipment at a time and are executed over several years. Delays in breaker upgrades or replacements may arise because of budgetary, operating, and manufacturer supply constraints. As a result, the time needed for breaker replacements may vary depending on the resources of the utility and the condition of the breakers that need to be replaced.

Knowing that replacing overstressed breakers may take a significant amount of time, utilities cannot operate power systems without considering overstressed breakers, because overstressed breakers are more likely to fail than breakers that are not overstressed. The operation of overstressed breakers leads to increased failure risks, risks of property losses, and degraded system reliability from extensive, common-mode outages. A failed breaker is a breaker lost for protection schemes. Stresses not handled by the failed breaker must be handled by surrounding portions of the system. These unintended transfers of stresses accelerate equipment degradation. This means the failure of overstressed breakers must be avoided when protection schemes are activated.

Circuit breaker adequacy and overstress problems can be circumvented on a temporary basis until overstressed breakers are upgraded or replaced, to the extent that addressing circuit breaker overstress is compatible with existing system operating constraints. Three types of corrective measures that can be combined for an increased impact are described in this chapter:

- Prevent circuit breaker operation when fault currents exceed breaker ratings;
- Reduce fault currents through overstressed breakers; and
- Reconfigure substations, temporarily, to control of the flow of fault currents through overstressed breakers.

These actions take advantage of the fact that overstressed breakers can still handle fault currents that are within their ratings, but that their protection role should be delegated under fault conditions that create breaker adequacy problems.

In this chapter, immediate applications of the corrective measures above to substation protection schemes are discussed, such as substation reconfiguration, generator dispatch, and the insertion of current limiting devices. In particular, for substation reconfiguration, an algorithm to determine a switching sequence is proposed that takes advantage of the ratings and stresses on other breakers to allow overstressed breakers to interrupt faults. These corrective actions are qualified of immediate because they can be implemented in the protection schemes at little to no capital cost while maintaining the necessary protection functionality.

6.2 Potential for Common-Mode Outages

Overstressed breakers have higher failure probabilities than breakers that operate within their interrupting capability. When breakers fail to clear a fault, backup protection schemes are activated until fault conditions are removed. The operation of backup protection as a result of a breaker failure results in power outages affecting additional areas besides the ones intended (Figure 31). Because such outages are linked to a single failure mode (the failure of a single breaker), such outages are referred to as common-mode outages.

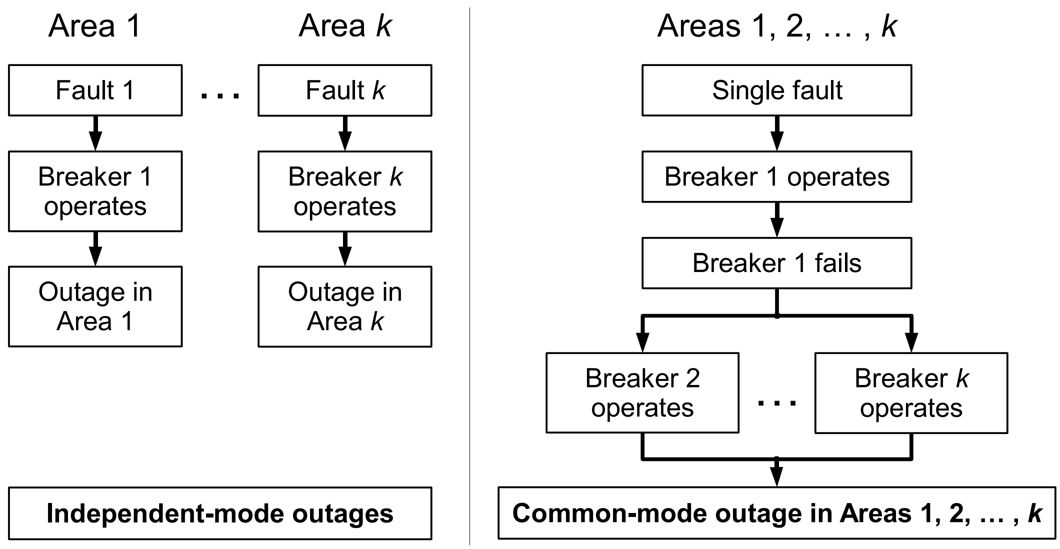


Figure 31: Genesis of common-mode outages vs. independent-mode outages.

The extent of the consequences of a breaker failure depends on the topology of the concerned substations and how failed breakers are connected to the rest of their parent substations. Generally, as shown in Figure 32, a breaker failure causes a number of breakers in substations surrounding the fault to operate. Substations with double-bus, double-breaker arrangements are the least vulnerable to breaker failures. In substations without internal path redundancy, such as the single bus/breaker arrangement, breaker failures result in the outage of all lines that converge at such substations.

The potential for large common-mode outages becomes a factor in the decision to operate an overstressed breaker. For example, breakers likely to cause extended common-mode outages are operated sparingly compared to breakers that could occasionally cause limited common-mode outages.

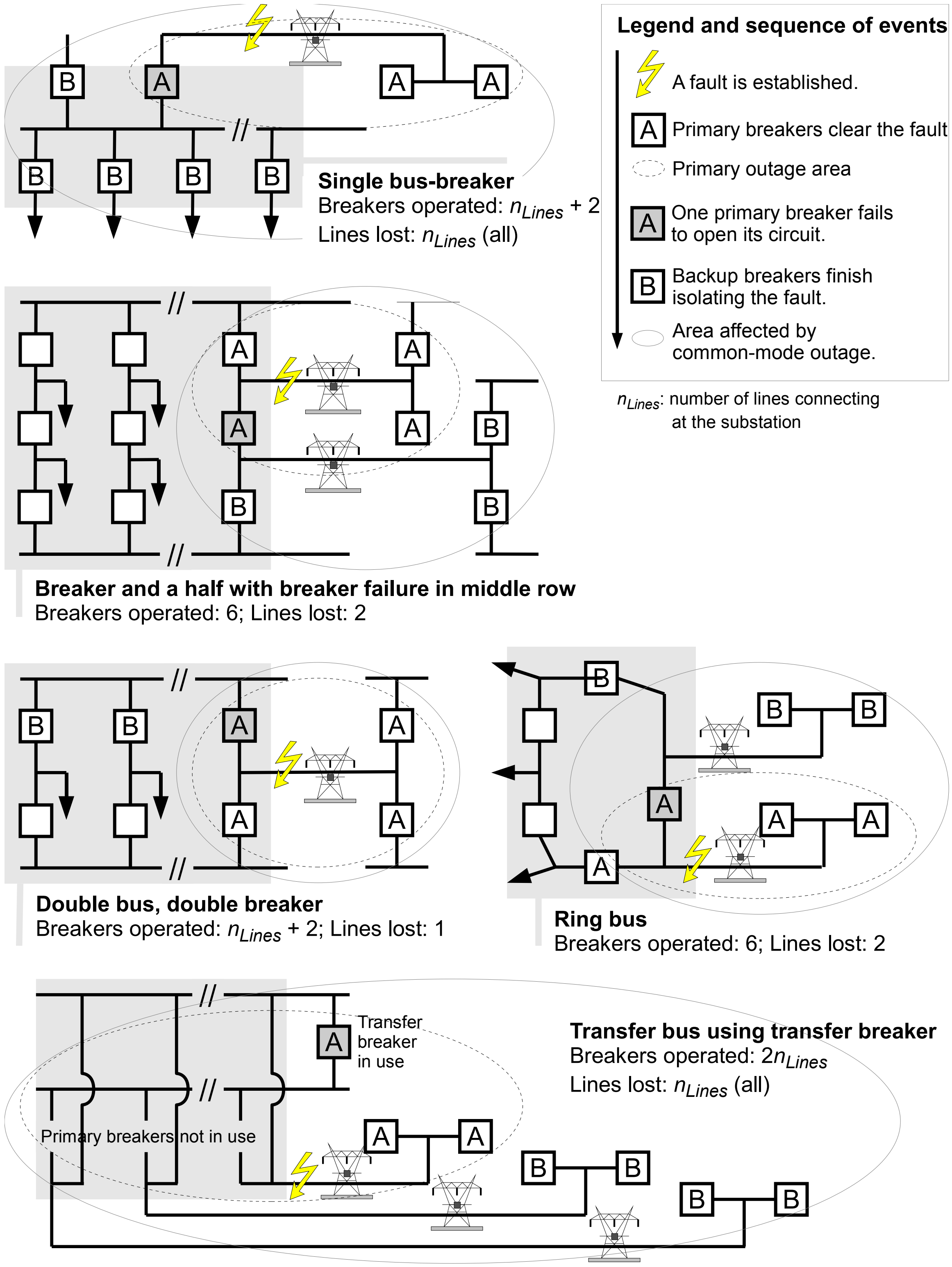


Figure 32: Backup protection (common-mode outage) propagation in common substation breaker arrangements.

6.3 Implications on Substation Protection

The following adjustments to substation protection schemes help keep circuit breakers within their operating limits. Each adjustment addresses one of the three aspects of focusing on circuit breaker reliability in power systems operations:

- Overstressed breakers are locked in closed or open position when fault currents are above breaker ratings.
- Current limiting devices in lines and substation branches reduce fault currents through overstressed breakers.
- Operating breakers in sequence and reconfiguring substation topologies help gain control of how fault currents flow throughout substations.

6.3.1 Adjustments to the Operations of Overdutied Breakers

The direct approach to prevent overstressed breakers from breaking fault currents in excess of their ratings consists of three remedial actions: (i) keeping overstressed breakers closed, (ii) keeping them open, and (iii) delaying their operation until the DC offset decays. This direct approach deals with the overstressed breakers themselves without considering the rest of the host substations.

6.3.1.1 Preventing Circuit Breaker Operation

Keeping overstressed breakers open or closed prevents their failures but imposes fault duty constraints on other circuit breakers.

On one hand, when a breaker is forced closed, the protective role normally assumed by the closed breaker must be transferred to other breakers within the substation without creating breaker adequacy problems. Adequacy problems arise when two or more breakers are triggered in sequence to clear a single fault. Indeed, after the operation of the first breaker, fault currents are distributed across fewer branches (Figure 33).

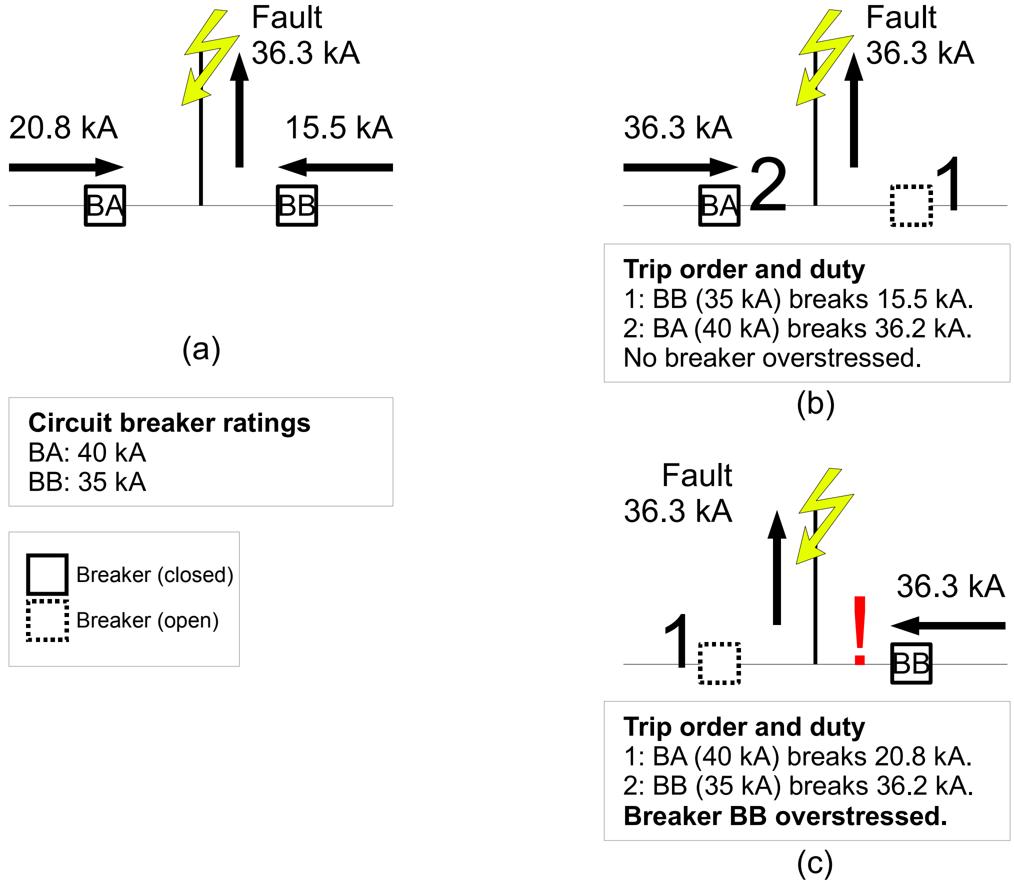


Figure 33: Illustration of breaker duties in different opening sequences.

On the other hand, with an open breaker in an affected substation, the statistical stresses of other breakers in the substation are changed as a result of a redistribution of fault currents across a reduced number of substation branches. (Fault currents are more "concentrated.") This results in increased fault currents through certain breakers. To continue reliable power system operations, keeping a breaker open should not create or worsen breaker adequacy issues.

6.3.1.2 Delaying Circuit Breaker Operation

Delayed breaker operations are possible when currents drawn by a fault marginally exceed the ratings of the breakers that must clear the fault.

Delaying breaker operation allows the DC offset to decay. The DC offset increases the RMS value of the current immediately after the onset of a fault (Equation (4) and Figure 5). The time delay to operate overdutied breakers extends the duration of fault conditions and must be compatible with the additional stresses that the affected equipment can bear.

Delaying relay/breaker operations may help solve the overstress problem for certain breakers and has several advantages:

- In a substation, only up to two breakers are affected.
- There is no loss of substation connectivity.
- The remedy is easy to implement using computer-based relays.

The drawbacks of delayed breaker operations are the following:

- Delayed breaker operations are possible only if the desired reduction of fault current levels does not exceed the possible reduction of the amplitude of the DC offset at the time of breaker operation.
- Fault conditions persist several cycles beyond the original instant of fault isolation.
- Delayed breaker operations may lead to system instability.
- The protective schemes of the substation must be tested to avoid undesired protection response.

6.3.2 Integration of Current Limiting Devices

Current limiting devices prevent fault currents from exceeding certain values. As a result, current limiting devices can be integrated into protection schemes to preserve the adequacy of otherwise overdutied breakers.

The specific effects sought from current limiting devices are to (i) bring fault currents below breaker ratings and (ii) obtain the desired protection response from protective relays.

The installation of current limiting devices does not require taking lines out of service or other heavy substation work. Devices that can be clamped to transmission lines and bus bars are being developed [156]. The knowledge of stress-induced breaker failure rates allows utilities and system operators to target the installation of current limiting devices to the breakers that have the highest risk of failure. Of course, to avoid undesired side effects, protection schemes must be adapted to account for the presence of current limiting devices.

6.3.3 Operating Overdutied Breakers in Sequence

Operating overdutied breakers in sequence and reconfiguring substations help control how fault currents are distributed throughout the branches of a substation. If two or more breakers protect a single line (in ring and breaker-and-a-half arrangements, for instance), currents are interrupted in successive stages that correspond to the opening of each breaker.

To operate overdutied breakers in sequence, the challenge is, ideally, to determine a sequence involving surrounding breakers in such a way that no breaker becomes overdutied as the sequence is executed. Specifically, when two breakers must isolate the same branch, opening one breaker results in fault currents being transferred to the other breaker (Figure 33). The transferred fault currents may cause other substation breakers that remain closed to become overstressed. Such side effects must be avoided to maintain appropriate circuit breaker and system reliability levels.

Using appropriate switching sequences, fault current levels through overstressed breakers can be reduced, and overstressed breakers may continue clearing faults without the risk of failure.

Operating breakers in a specific order is possible with computer-based relays using the high-speed communications technology and infrastructure available.

6.3.4 Substation Topologies to Preserve Breaker Adequacy

Adjusting, delaying, or preventing circuit breaker operation, integrating current limiting devices, and operating breakers in sequence are remedies that can be combined to obtain network or substation topologies that preserve circuit breaker adequacy. Ultimately, power systems should operate with the objective of minimizing circuit breaker failure or minimizing circuit breaker overstress. Topologies that preserve circuit breaker adequacy can serve in two opposite scenarios:

- Transient topologies are maintained while appropriate breakers remove contributions to fault currents, taking excess duty away from the most overstressed breakers. The breakers that were overstressed can at that point clear the fault without loss of reliability. The original system topology is restored after fault conditions are cleared.

- Permanent topologies that minimize breaker failures and that are viable for continued system operation can be applied system-wide (at the control center level) or locally at every substation. The use of such topologies is intended to last until overstressed breakers are upgraded.

6.3.4.1 General Algorithm for Real-Time Substation Topology Switching

Temporary reconfigurations of substations are important to minimize the area affected by the operation of circuit breakers. After the removal of faults, the initial configurations of substations are restored. This approach is similar to reclosing scenarios commonly used with distribution breakers: if a fault on a distribution system is permanent, the distribution system is reconfigured by closing a normally-open tie line; reclosers are activated to isolate the fault while maintaining service to the rest of the distribution system. In this section, a general algorithm to determine a substation switching sequence that accounts for circuit breaker stresses and ratings during faults is described.

The strength of the topology switching approach is in the interrupting capabilities of other circuit breakers of the substation. In a substation with path redundancy, breakers can be operated to bring fault currents to a level that is below the ratings of overstressed breakers that need to isolate the considered fault.

Topology switching requires a real-time model of fault currents for worst-case faults. Worst-case faults are faults on buses with virtually no limiting impedance between the fault and the breakers that must be operated. A real-time model is needed to determine whether breakers are overstressed when a fault occurs. The knowledge of the exact location of the fault using the communication features of protective relays is essential for topology switching to be effective. Different criteria such as breaker ratings, failure rates, and operating margins can be used to select switching topologies. To simplify the illustration of the concepts introduced in earlier chapters, this part only considers the rating of the breakers as the most important factor.

The selection of topology switching sequences should be performed offline with simulated faults. Working with simulated faults allows testing and refining the selected switching sequence to avoid undesired responses or side effects. In addition, if no suitable switching sequence has been found, an alarm can be generated to have further remedial actions decided by system operators instead of an unavoidable breaker failure in a real situation.

In the proposed methodology and examples, the term "primary breaker" designates breakers that are in immediate proximity of a given fault. Primary breakers clear the fault while removing power from the smallest area possible.

The general algorithm to select a topology switching sequence for a given substation and a simulated fault is outlined in Figure 34.

In terms of substation protection, the implications of circuit breaker operating limits can be summarized with the following question: For each worst-case fault, is there a temporary substation configuration that allows safe switching of the fault? Among a family of faults (e.g. line-to-neutral faults on a given line), a worst-case fault is a fault that draws the highest current compared to other faults in the same family. For transmission lines, the worst-case faults considered are bus faults at either end of each transmission lines. Also, different types of faults draw different currents; for instance, three-phase bus faults are the most severe type of fault for which a protection plan should be available.

It is not always desirable or possible to change substation topologies to reduce the duty of overstressed breakers. Substation reconfigurations may not be practical if intermediate circuit breaker operations before fault isolation cause undesired outages. Concerns about system stability arise every time a breaker is operated, and there may be critical durations beyond which temporary configurations cause generator instability. Furthermore, topologies where no circuit breaker is overdutied do not necessary exist; in such cases, other remedial actions must be applied to prevent breaker failures.

6.4 Implications on Economic Dispatch

6.4.1 Generator Commitment and Fault Currents

Reducing the number of generators connected to the system (the generator dispatch), i.e. reducing the available generating capacity is a more direct means to reduce fault currents through overstressed breakers than reconfiguring substation or even inserting fault current limiters. Indeed, it is the available capacity of a connected generator that determines the magnitude of fault currents contributed by the generator, not the

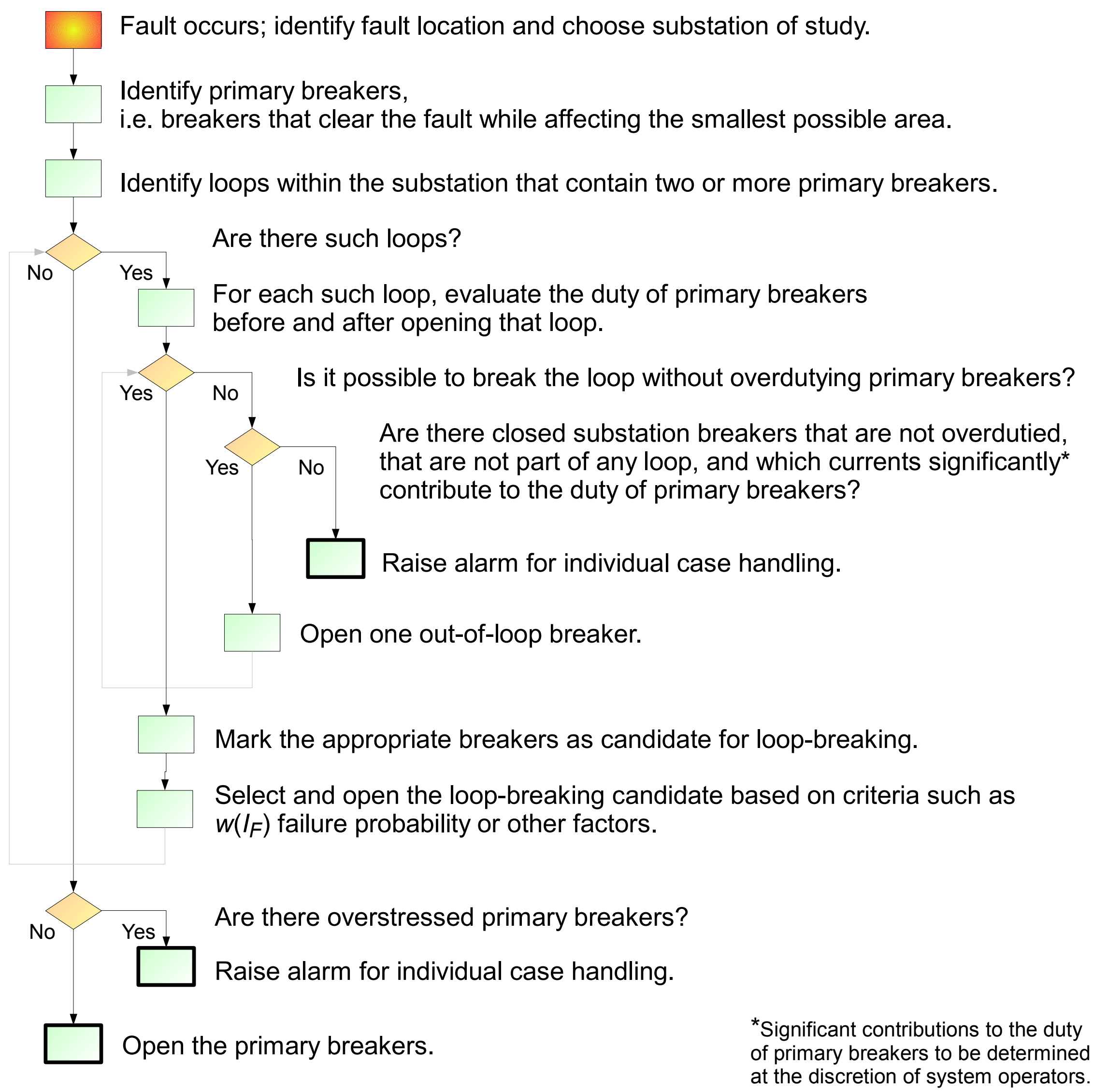


Figure 34: Algorithm for the selection of a topology switching sequence.

generated power. Acting on generator commitment tackles the source of the problem: increased generation capacity from large utility plants to independently-owned, distributed sources. These adjustment also benefit circuit breakers in substations immediately neighboring the concerned generators because of the relatively low impedance in between. (The effect of generator output adjustments dampens with distance.)

Adjustments to the economic dispatch are best applied to plants where several generators do not run at full capacity. In such cases, the output of several generators can be consolidated, resulting in fewer sources of fault currents. The same strategy can be applied at new generating plants connected to the network because the output of new generating plants is meant to gradually increase with the demand over several years.

It is important to note that generator output adjustments are not available during peak times, when the available generating capacity is fully utilized. Also, operating constraints for each generator, such as fuel supplies, startup and shutdown times, may limit the extent to which the output power from the generators can be consolidated.

Thanks to the linearity of transmission systems, the contribution of generators brought into service to the fault duty of circuit breakers can be quantified by performing fault analysis on the studied breakers before and after connecting the dispatched generators to the rest of the grid.

There are two ways to incorporate circuit breaker operating limits into the economic dispatch problem: (i) by maximizing the total power available or (ii) by minimizing breaker failure rates. The formulation of these two problems is described next.

6.4.2 Maximizing the Total Power Available

In this approach, the objective is to maximize the total available power while limiting fault currents (and stress-induced failures) through closed breakers:

$$\begin{aligned} \text{maximize} \quad & \sum_i P_{g,i} x_i \\ \text{subject to} \quad & \sum_i I^k_{gc,i} x_i \leq I^k_N \quad \forall k \in K_j \\ & x_i \in \{0,1\} \ \forall \ i, \end{aligned}$$

where

$x_i = 1$ if generator i is connected, 0 otherwise,

$P_{g,i}$ is the output of generator i,

K_j is the set of closed breakers in network configuration j,

I^k_N is the rating of circuit breaker k, and

$I^k_{gc,i,j}$ is the fault contribution of generator i to circuit breaker k in configuration j.

The decision variables are the network configuration K_j and the boolean variables x_i that determine whether generators are in service or not.

6.4.3 Minimizing Circuit Breaker Failure

In this approach, the goal is to minimize stress-induced circuit breaker failures while serving all loads in the system:

$$\begin{aligned} \text{minimize} \quad & \sum_{k \in K_j} P_{Stress,k} \\ \text{subject to} \quad & \sum_i P_{g,i} x_i - P_{Load} - P_{Losses} = 0 \\ & x_i \in \{0,1\} \ \forall \ i. \end{aligned}$$

Again, the decision variables are the network configuration K_j and the boolean variables x_i that determine whether generators are in service or not.

6.4.4 Economic Dispatch Integration

The constraints brought by these two approaches result in a new constrained economic dispatch problem:

$$
\begin{aligned}
\text{minimize} \quad & \sum_i f_i(P_{g,i}) - B_1 \sum_i P_{g,i} x_i + B_2 \sum_{k \in K_j} P_{Stress,k} \\
\text{subject to} \quad & \sum_i P_{g,i} x_i - P_{Load} - P_{Losses} = 0 \\
& x_i P_{g,i,min} \leq P_{g,i} \leq x_i P_{g,i,max} \ \forall \ i \\
& B_1 \sum_i I^k_{gc,i,j} x_i \leq B_1 I^k_N \quad \forall k \in K_j \\
& B_2 P_{BF,k} \leq B_2 \hat{P} \quad \forall k \in K_j \\
& x_i \in \{0, 1\} \ \forall \ i \\
& B_1 \geq 0 \text{ and } B_2 \geq 0,
\end{aligned}
$$

where B_1 and B_2 are the relative cost of integrating the circuit breaker operating limits in the economic dispatch problem. (B_1 is associated with a negative sign to maximize the total available power.)

Because this problem is a mixed-integer programming problem, a solution may be obtained using optimization techniques such as genetic algorithms, particle swarm solutions, and so on. In the numerical example of Chapter 7, simple applications of the two proposed approaches are compared.

It is clear that constraints on economic dispatch and switching sequences are not designed to be long-term alternatives to replacing overdutied breakers, but rather short-term operating strategies to preserve circuit breaker adequacies before the purchase and replacement of overdutied breakers can be completed.

6.5 *Implications on Control Center Applications*

Control centers use network data to run load flow analyses, state estimation, and various types of energy management systems (EMS) applications. Operators at control centers have authority to override relays and manually open/close breakers. With the massive amount of information that already flows into control centers, operators must quickly understand arising situations and make decisions that are critical to maintaining the reliability of power systems.

Circuit breaker monitoring is possible from relays or from control centers. Although relays perform instantaneous performance and status monitoring [74], breaker duty monitoring from control centers benefits from the knowledge of the topology of the network and the availability of circuit breaker data as a single entity. With comprehensive circuit breaker and network information, control centers can perform system-wide circuit breaker reliability analysis in conjunction with load flows and fault analyses. The principle of this application is outlined in the workflow shown in Figure 35.

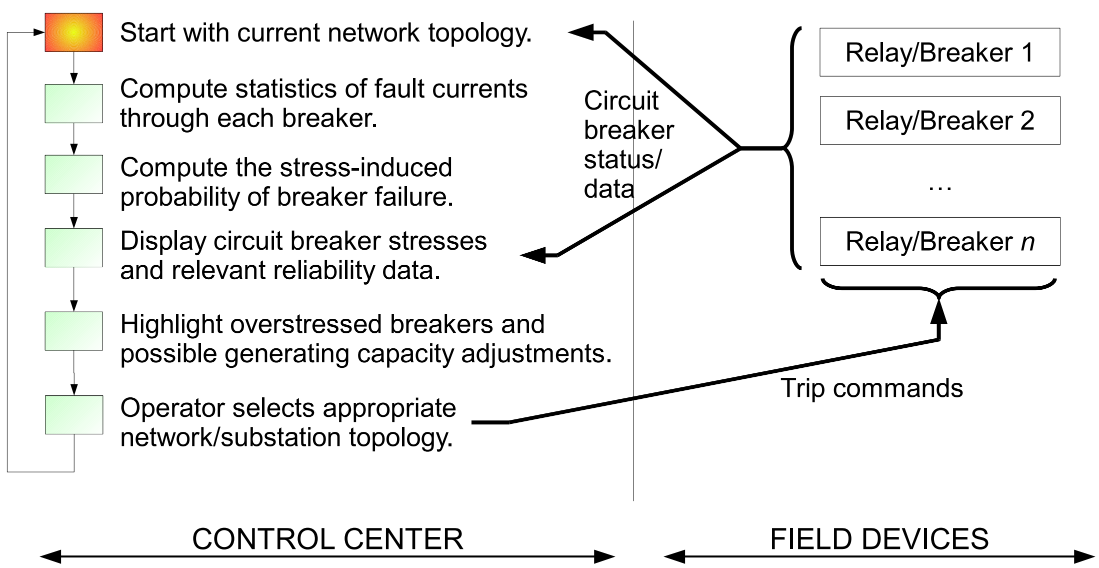


Figure 35: Concept workflow for monitoring and addressing circuit breaker overstress in control centers.

Displays of the overall status of the breakers can be completed as a control center application. Such displays provide visual clues, such as bars and arrows, that help determine which circuit breakers are overdutied, which breakers need maintenance, and so on. An example of such a display is presented in Chapter 7.

The control center application introduced in this section can benefit from the selection of paths that minimize breaker failure by presenting different options to system operators in advance of faults. Operators select which network/substation reconfiguration scheme should be used based on their experience and knowledge of the network.

6.6 Summary

In this chapter, strategies to circumvent the issue of circuit breaker overstress are presented. These strategies can be combined to reduce breaker reliability constraints. The simplest but restrictive solution is to lock overstressed breakers closed or open. Delayed breaker operations may be successful if fault current RMS values do not exceed breaker ratings by more than the DC offset and the protected equipment can withstand prolonged fault conditions.

With current limiting devices gaining in popularity and maturity, current limiting devices properly selected, placed in series with overstressed breakers appear to address circuit breaker adequacy with minimum impact.

Substation reconfiguration is a means to redistribute fault currents and adjust the balance between breaker interrupting capabilities and fault current magnitudes. Also, currents can be redirected from generators through long sections of the system instead of directly flowing into a fault. The increased impedances of reconfigured paths reduce the magnitude of fault currents significantly.

Adjusting generator commitment tackles the source of circuit breaker adequacy problem: increased generation capacity. The available capacity of a connected generator, not the generated power, determines the fault currents contributed by that generator. The consolidation of generator output is available if the resulting reduction in generating capacity allows the system to meet the demand. Specifically, this operating strategy is not available when the electricity demand peaks.

To achieve power systems operations that account for circuit breaker operating limits, circuit breaker reliability constraints are incorporated into two new formulations of the economic dispatch problem. The solution of the economic dispatch problem may or may not be compatible with operating policies of the utilities if, for instance, generation margins are not sufficient or operating costs exceed acceptable limits.

In Chapter 7, the strategies to address circuit breaker adequacy issues are illustrated with a test system and a possible responses to certain fault conditions.

CHAPTER VII

ILLUSTRATIVE APPLICATION TO A 24-SUBSTATION TEST SYSTEM

7.1 Overview

This chapter consists of numerical examples illustrating the circuit breaker adequacy issues presented throughout this study. Examples of circuit breaker adequacy, fault, and reliability analysis are illustrated using a physical, three-phase, breaker-oriented system based on the IEEE 24-bus system. The generator dispatch, power flow, and initial circuit breaker data of the test system are provided as initial assumptions. Different means to monitor circuit breaker reliability data are also presented to give system operators a quick overall understanding of breaker reliability issues.

Several scenarios are considered as an illustration of circuit breaker adequacy and reliability issues. First, failure data are compared when factors that affect fault statistics are changed, such as the type of faults, the maximum fault-to-breaker distance, and the connectivity of substations. The effect of the addition of new generating capacity on circuit breaker duty is then considered, with an analysis of the impact on breaker failures and reliability data in the short and long term.

Scenarios involving a simulated fault are also considered, and in each scenario, a fault clearing strategy that circumvents circuit breaker overstress is presented. Three types of remedial actions to circumvent circuit breaker adequacy issues are illustrated with (i) an example of circuit breaker operation in sequence, (ii) an example with an adjustment of generator dispatch, and (iii) an example illustrating the effect of a current limiting device on fault currents.

Perspectives for immediate applications of the proposed methodology are also suggested, such as statistical circuit breaker duty monitoring and related control center applications.

7.2 Proposed Three-Phase, Breaker-Oriented, 24-Substation Reliability Test System

The proposed test system for breaker fault and reliability analysis is based on the IEEE Reliability Test System (RTS), also known as the IEEE 24-bus system.

The IEEE RTS, first published in 1979 [29], is a reference electric network model to compare different reliability assessment methodologies based on a common set of generator and transmission line data, such as fuel costs, power ratings, line impedances, and outage information. The test system is a single-line equivalent network model defined with positive sequence, pi-equivalent parameters. The system consists of 24 buses with generators and loads distributed across two areas with different voltage levels (138 and 230 kV). The RTS was updated in 1986 and 1996 [30] to provide additional data for the generation system and to accommodate new methodologies for power system reliability assessment. The 1996 update is also noteworthy for providing examples of breaker arrangements at every bus of the RTS.

In this study, the IEEE RTS is modified to enable fault analysis at the circuit breaker level and to provide a three-phase network model that accurately captures the phenomena of physical systems. Circuit breaker reliability studies now have access to accurate fault data for each breaker in the test system.

Each bus in the 24-bus system is replaced with a substation with the corresponding breaker arrangement found in the 1996 update of the IEEE RTS. An overview of the resulting test system is shown in Figure 36.

The proposed test system includes 188 breakers distributed in 24 substations. The system is breaker-oriented because the arrangement of circuit breakers at every substation is represented explicitly. Details of the breaker arrangements at two substations are shown in Figure 37.

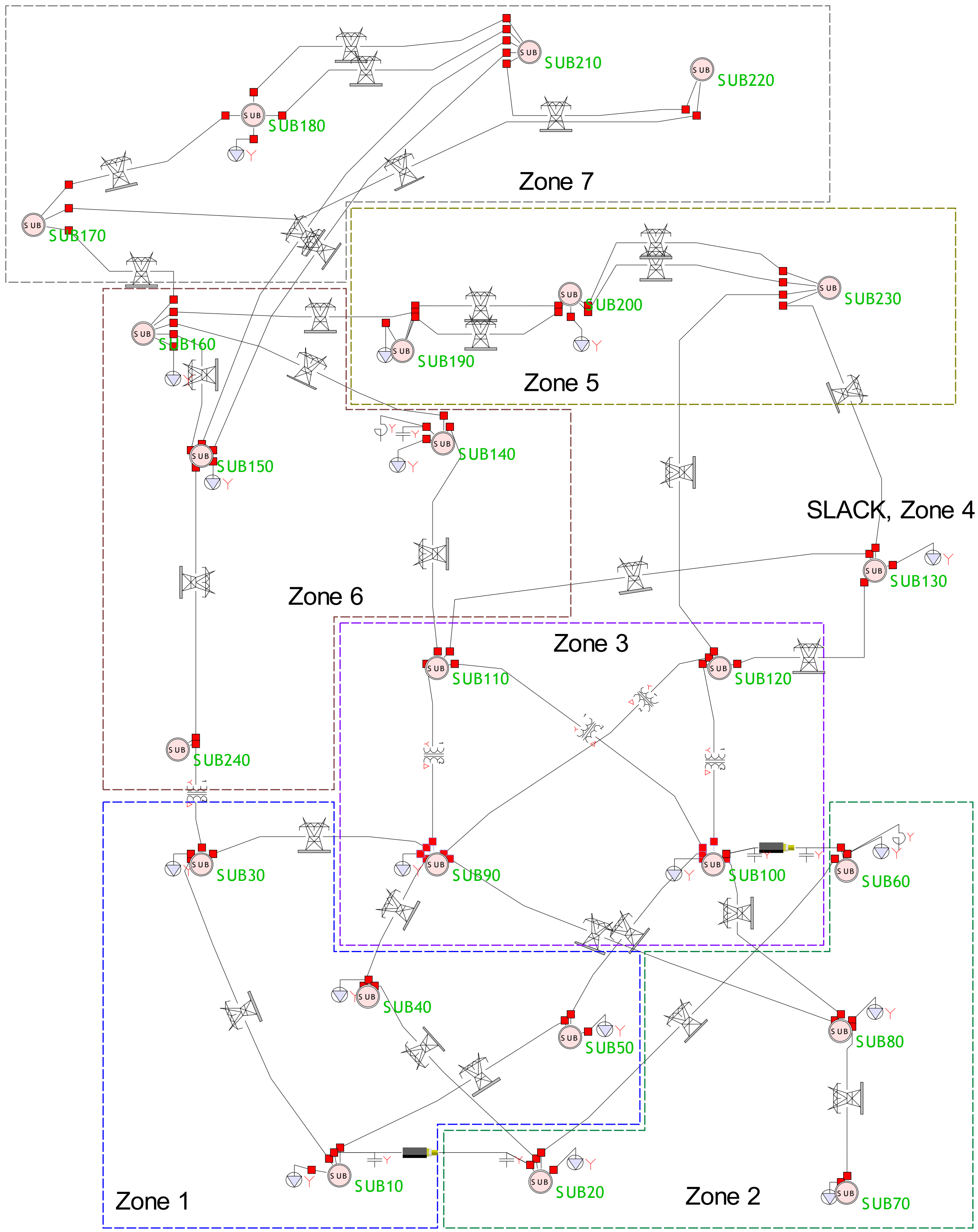


Figure 36: The proposed three-phase, breaker-oriented, 24-substation test system.

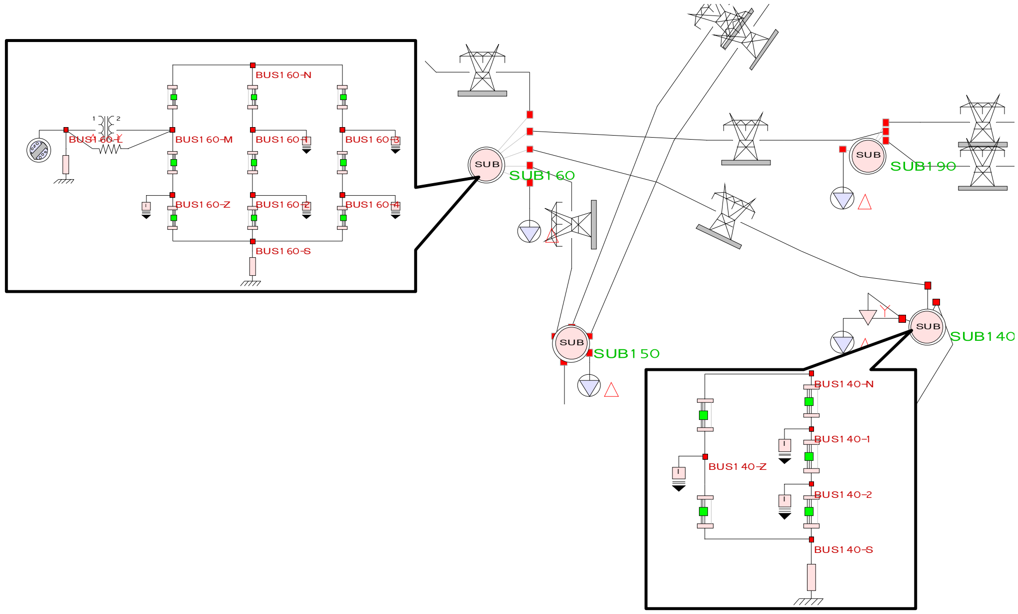


Figure 37: Breaker arrangements at two substations of the proposed breaker-oriented, 24-substation test system.

Unlike the original test system, which is a single-line, positive sequence equivalent of a power network, the modified test system is a three-phase network model based on physical parameters of transmission lines. All three phases, the neutral, and grounding are modeled explicitly to allow independent computations of the electrical quantities in each conductor. Physical parameters are such that the pi-equivalent, positive sequence models of the lines have the same parameters (or similar parameters) as in the original test system (Figure 38). Slight deviations from the “ideal” parameters defined in the test system are unavoidable when combining transmission line geometry and cable properties.

The proposed 24-substation test system is modeled using the WinIGS simulation software from Advanced Grounding Concepts (http://www.ap-concepts.com/). Complete data for the test system, including line, generator, transformer, and load data, are publicly available for download (http://pscal.ece.gatech.edu/testsys/).

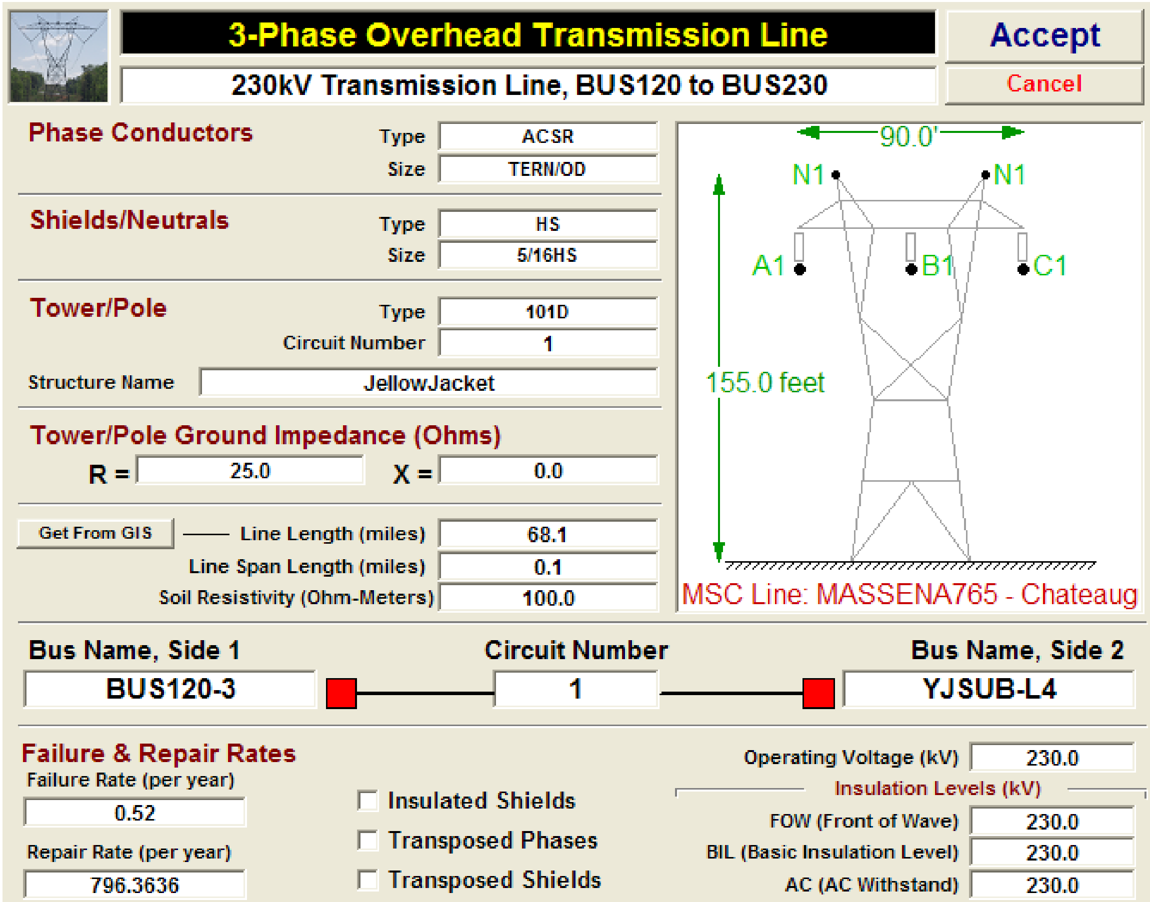


Figure 38: Sample user interface from the WinIGS software to define the parameters of a three-phase, physical transmission line model.

7.3 Initial Operational Data

7.3.1 Initial Generator Dispatch and Power Flow

The analysis starts with a base case in which the output power of each generator is initialized. In this example, generator outputs are initialized from data published in a study on economic dispatch with minimization of line losses [157]. The aggregated generator outputs at each main bus is shown in Table 14. The table also shows the type of buses (PV or PQ) that are adopted in this particular example. Other possible values to initialize generator outputs are given in the 1996 definition of the IEEE RTS [30]. The generator output the reader elects to assign should be validated by making the base power flow converge.

Table 14: Example of generator dispatch for the IEEE 24-bus system (taken from [157]).

Bus	Type	P_g (MW)	Q_g (MVAR)
1	PV	180	13.43
2	PV	180	−18.16
7	PV	240	43.88
13	PV	100	87.24
15	Slack	200	−17.83
16	PV	200	29.38
18	PV	400	140.74
21	PV	400	111.14
22	PV	300	−30.51

7.3.2 Circuit Breaker Fault Analysis

The analysis of the duty of circuit breakers is performed using the breaker-oriented, three-phase fault analysis methodology presented in Chapter 5. The fault current PDF is computed for all 188 breakers in the test system using the WinIGS software. The set of fault current PDFs are the basis for all reliability computations and for determining operational strategies.

7.3.3 Circuit Breaker Reliability Data

7.3.3.1 Age and Related Failure Rates

Circuit breaker ages are randomly assigned according to a uniform distribution with a mean of 40 years and a spread of ±20 years. The age distribution of the breakers is shown in Figure 39.

Age-related failures are modeled using the following bathtub (Weibull) function, also assuming a 40-year design MTTF ($\lambda = 1/\text{MTTF}$) and parameters $\alpha_1 = 0.5$, $\alpha_2 = 1$, and $\alpha_3 = 10$:

$$\lambda_{aging}(t) = \sum_{i=1}^{3} \alpha_i \lambda (\lambda t)^{\alpha_i - 1} \tag{42}$$

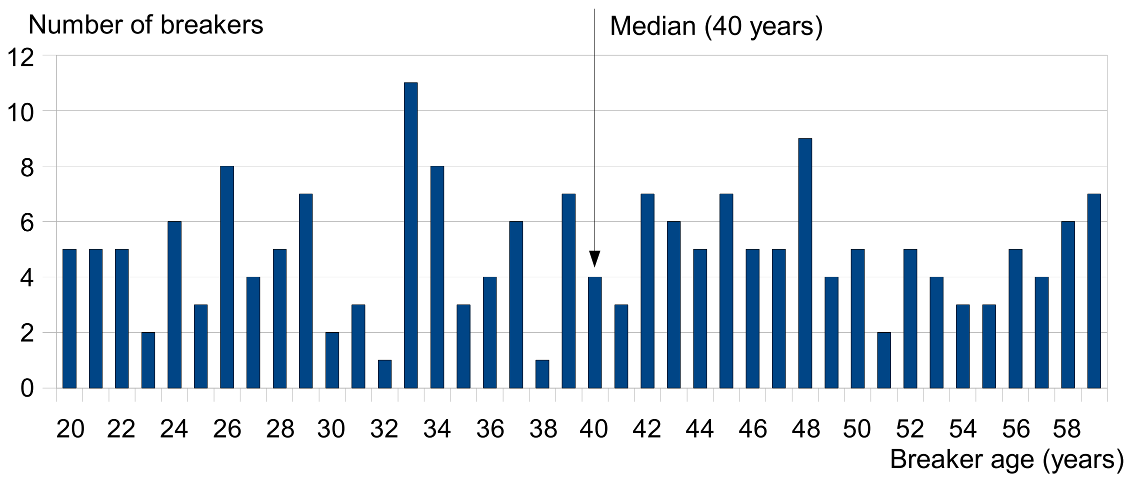


Figure 39: Age distribution of the circuit breakers in the test system.

Field data, such as annual breaker failure rates from the CIGRÉ survey of circuit breaker reliability [158], may be used to match the proposed aging model with actual conditions.

Knowing the circuit breaker ages is not only essential to determine age-related failure rates, but also to compute reliability quantities linked to the operating history of the breakers.

7.3.3.2 Failure Thresholds and Estimated Interruption History

Besides the rated breaking current I_N, each circuit breaker has a history of interruptions summarized by the total current interrupted and the number of fault clearing operations. The interrupting thresholds I_0 and I_1 at the beginning of the considered time horizon are estimated according to an estimated interruption history using Equations (25) and (26), rewritten below for reference:

$$\begin{aligned} I_1(t) &= I_1(t_0)\left(1 - 0.1\frac{I_{Cumul}(t)}{I_{Std}}\right), \\ I_0(t) &= 0.75\ I_1(t). \end{aligned}$$

All time-dependent quantities are referred from the time reference t_0 (e.g. the initial commisioning or the latest maintenance of the considered breaker).

Cumulated breaker duty and number of operations are related because both are estimated based on the age of circuit breakers. As a matter of fact, when expressed in per-unit values (as a fraction of the standard cumulated duty or standard number of operations recommended by standards), the estimated cumulated duty and number of operations are identical.

The per-unit cumulated duty is utilized to compare the relative maintenance needs of breakers at different stages of their lifetime. Specifically, 1 per unit means the endurance or prescribed cumulated duty for a particular device has been exhausted. To emulate the effect of maintenance of different units at different times, the cumulated duty is restricted between 0 and 1.2 per unit. Once the cumulated duty reaches 1.2 per unit, breaker maintenance takes place, and the cumulated duty is reset to zero.

7.3.3.3 Stress-Induced Breaker Failures

For each breaker in the test system, the stress-induced failure probability P_{Stress} is computed using the generated fault current PDF. The procedure to determine P_{Stress} is described in Chapter 5.

Breaker failure data are determined from pre-computed breaker ratings that are, in turn, generated from the maximum duty found in the breaker fault current PDF. Breaker ratings are generated by rounding the maximum fault duty to the nearest even kA rating. For instance, breakers with maximum fault currents of 15.1 kA and 14.9 kA are assigned a rating of 16 kA and 14 kA, respectively. The generated ratings do not necessarily correspond to typical ratings, but have the advantage of "making" a number of breakers overstressed on purpose.

A graphical overview of the values for P_{Stress} is provided in Figure 40. In the figure, a plus sign marks the number of breakers (one breaker in most cases) for which P_{Stress} has the corresponding value in abscissa; the continuous graph represents the count of breakers that have P_{Stress} less than the abscissa value of that probability.

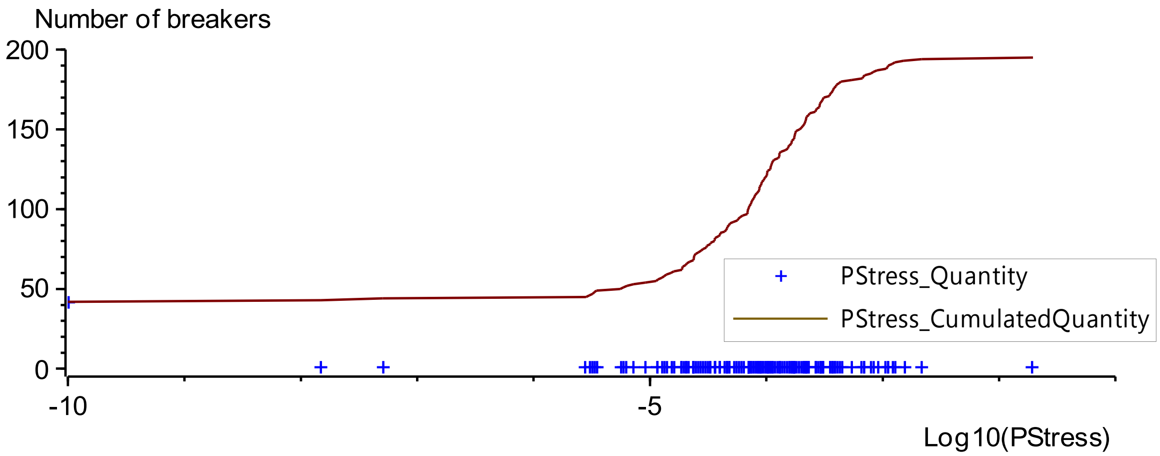


Figure 40: P_{Stress} probability distribution for the circuit breakers in the proposed test system.

7.4 Factors that Affect Fault Current Statistics

The shape of the $w(I_F)$ function obtained from the Monte Carlo fault analysis depends on a number of factors. Variations in these factors affect the contribution of stresses to breaker failures and system reliability. Variations of the stress-induced failure probability P_{Stress} resulting from network expansion, changes in the maximum distance between the considered faults and the studied breaker, and changes in the connectivity of the hosting substation are considered in this example. The effect of different types of faults on statiscal stress levels, the stress-induced failure probability, and the overall reliability of the considered circuit breaker is also introduced.

The same breaker in the proposed test system is used to illustrate the factors discussed above.

7.4.1 Maximum Distance from Breaker to Fault

Fault distributions are compared for faults anywhere in the system (Case (a)), and within 70 miles (Case (b)) and 50 miles (Case (c)) from the studied breaker (Figure 41). The computed failure rate is almost identical in the three cases despite the fact that the relative weight of high fault currents increases in the $w(I_F)$ distribution.

There are two reasons for this observation: (i) although the scale of the current PDF is changed, restricting faults to a radius around the studied breaker does not affect the shape of the failure probability density at high currents and (ii) the conditional probability density of fault currents utilized in this paper already scales the failure probability density. The fault current PDF assuming breaker operation, $W_{Op}(I_F)$, already implies constraints on the magnitude (i.e. distance) of faults that the breaker is going to trip.

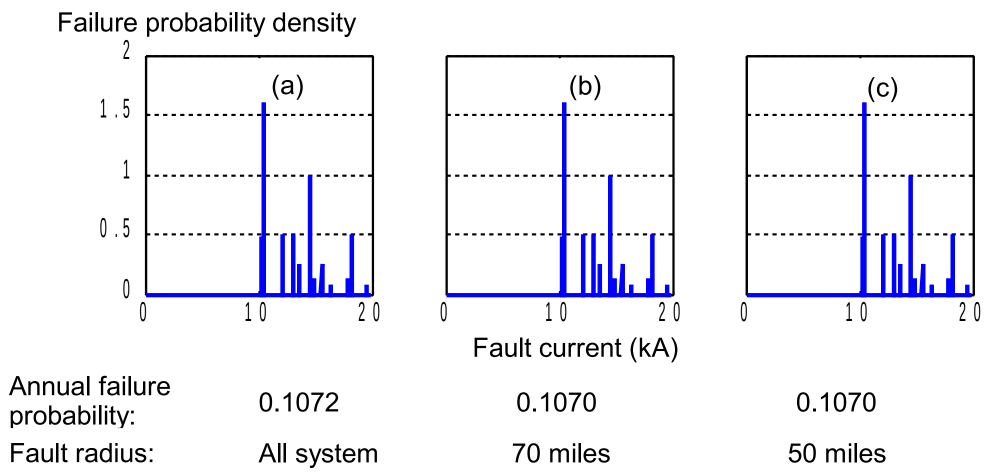


Figure 41: Effect of the maximum fault distance on breaker stresses.

7.4.2 Fault Types and Probability

Line-to-ground, line-to-line, and three-phase faults do not occur with the same probability (Table 5 in Chapter 2). Single-line-to neutral/ground faults are the most common. The accuracy of the distribution of fault currents depends on how close the relative statistical frequencies of the simulated faults are from reality.

To give the reader an idea of the expected effects, results from a limited number of faults simulated on lines that connect to the substation containing the studied circuit breaker are provided. Four fault current PDFs are manually computed, one for each fault type considered, and the current PDFs are weighted using the factors found in Table 5. There are slight differences in the PDFs from one type of fault to the other.

The differences can be visually tracked by placing the fault PDFs side by side, as shown in Figure 42.

Differences in statistical failure probabilities may vary from one system to another when considering only one versus several types of faults. Depending on the characteristics of the system studied, the differences may be significant enough to improve or deteriorate circuit breaker reliability indices.

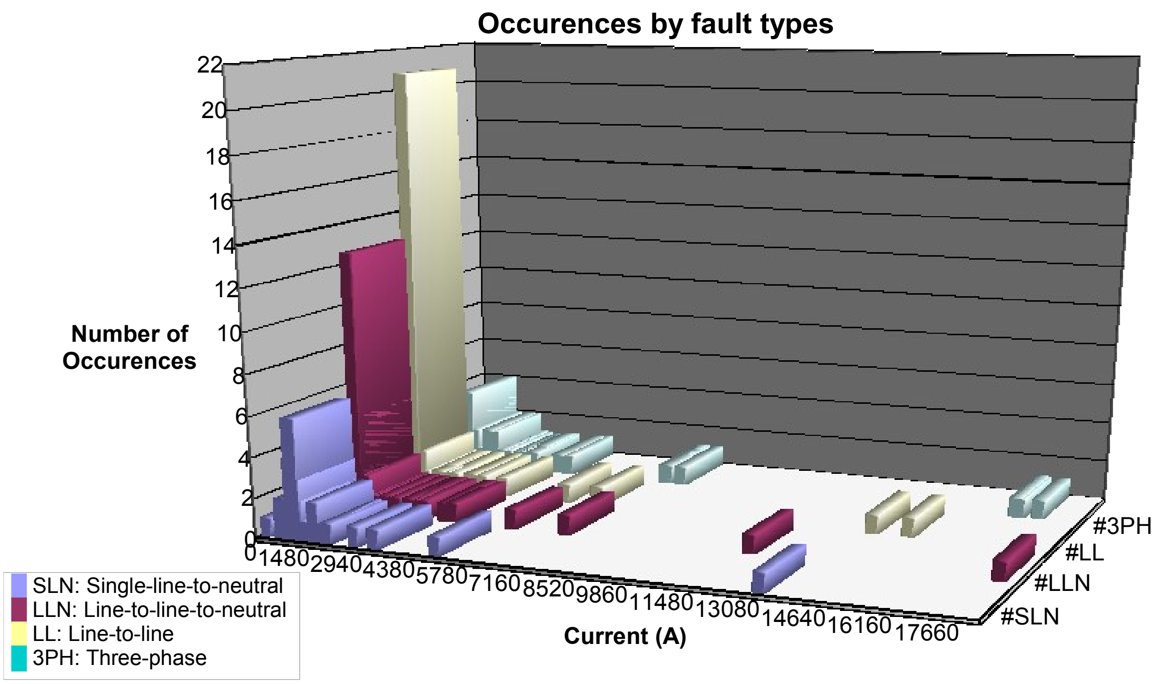


Figure 42: Visual comparison of fault current statistics by fault type.

The study of the effect of different types of faults on the fault current densities can be automated with a selection of fault types to consider when performing the Monte Carlo simulation of system faults. The selection of the considered fault types can be integrated into the WinIGS fault current distribution feature, for instance.

7.4.3 Substation Connectivity

The effect of substation connectivity is highlighted in Section 7.7.3 dealing with switching sequences. When breakers open one after the other, several intermediate states of substation connectivity are revealed, and fault currents through the involved breakers vary with the equivalent impedance of the paths available within the substation.

7.5 *Impact of Generating Plant Additions on Breaker Failures*

In this section, two combined generating plants are added to the proposed test system. The added generating capacity is 4 × 155 MW at each plant substation. The total increase in generation capacity is 1.24 GW. The following example demonstrates how the addition of generating units makes certain breakers overdutied, and how such additions affect circuit breaker reliability indices.

The generator substation layout is shown in Figure 43. The new generator substations connect with the rest of the network at Substation 230, as shown in Figure 44. The new substations are numbered 230-A and 230-C.

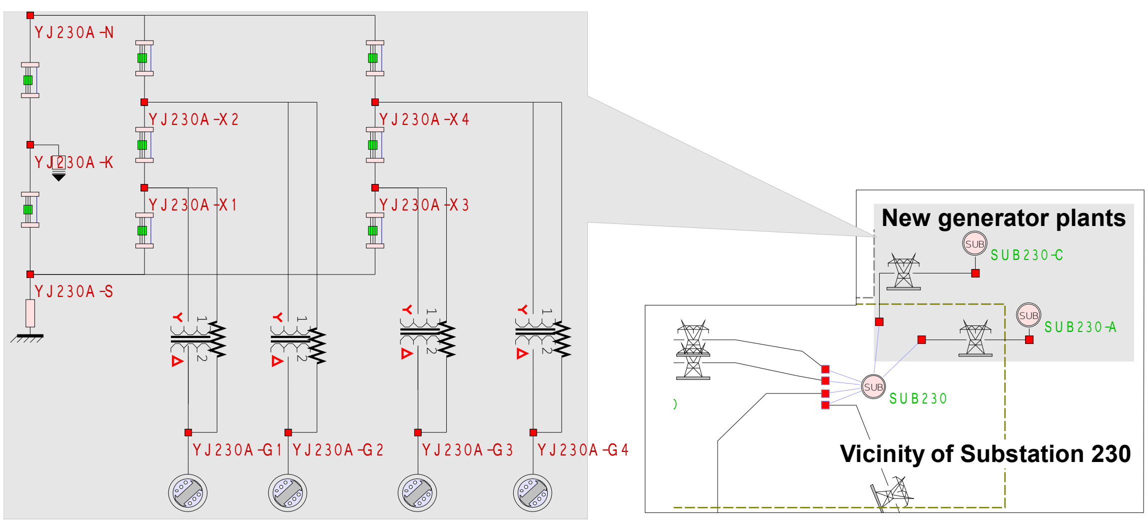


Figure 43: Topology of the two generating plants added to the network.

The breaker considered in this example is Breaker 185 in Figure 44. In Figure 45, the statistical fault current levels for the considered breaker are shown before and after the addition of the two generating plants. A shift in the fault current PDF towards high currents is apparent when new plants are connected with the rest of the system.

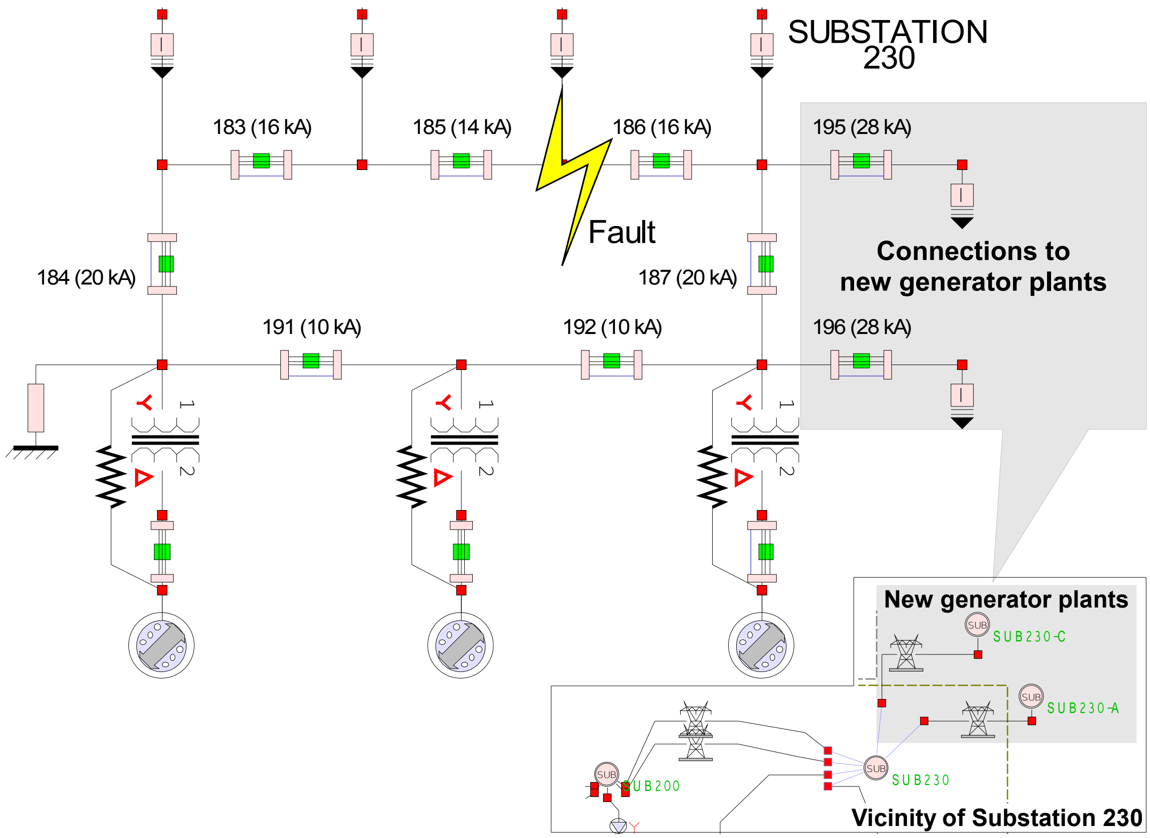


Figure 44: Connections of new generator plants to the test system.

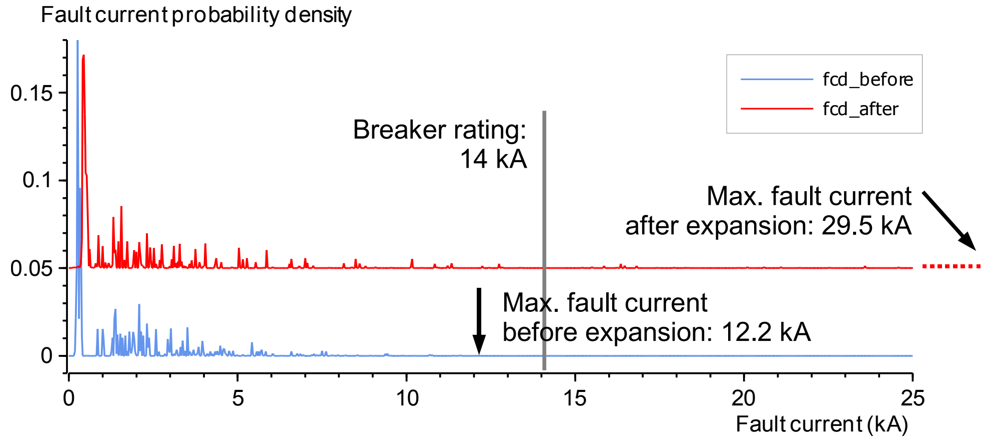


Figure 45: Comparison of statistical fault current levels at Breaker 185 before and after connecting new generating plants to the test system.

Assuming that Breaker 185 has a 14 kA rating, the rating is appropriate for the initial case where maximum fault currents do not exceed 12.2 kA. After the addition of the new generating plants, the maximum fault current level is 29 kA and largely exceeds the original rating of the breaker. Breaker 185 has become overdutied.

Based on the PDFs of fault currents shown in Figure 45, the breaker failure probabilities before and after connecting the new generator plants are as follows:

- Before (initial failure probability): 6.68×10^{-5}
- After (final failure probability): 1.80×10^{-4}

The breaker data used to compute the numbers above are as follows: rating: 14 kA; and minimum operating current of 2.1 kA.

As expected from the shifting of the fault current PDF to high fault levels, the addition of the new generator plants increased the failure probability of the studied breaker. Factors such as DC offset and endurance have not been taken into consideration at this point and are described in further detail in the next section.

7.6 *Impact of Generation Growth Forecast on Breaker Failures*

7.6.1 Generation Capacity Growth Scenario

The proposed test system is extended several times with generator substations and short lines that link the new plants to the rest of the system. Small generators are also added to represent distributed sources at substations that do not originally have generators. The generation capacity growth scenario is outlined in Table 15, adding 434 MW of capacity to the proposed test system over 10 years. (+14 % or +1.5 %/year average increase). Fault analysis is performed for the focused breaker at every update of the system model.

This generation capacity growth scenario uses the proposed 24-substation test system with some adjustments in the initial power flow data. To help retain the relevant faults that the focused breaker may eventually interrupt, the location of the simulated faults is limited to a 70-mile radius around the substation. This radius is just above the length of the longest line leaving Substation 230 in the test system (67 miles), and the considered area covers Zone 2 of the distance protection function.

Table 15: Generation capacity growth example scenario.

Year	Affected Substation	Added Capacity (MW)	Total Capacity (MW)
0 (t_0)	N/A	Initial system	3150
1 (t_1)	Substation 190	+20	3170
2 (t_2)	Substation 240	+12	3182
3 (t_3)	New Substation 250	+155	3337
4 (t_4)	N/A	No additions	3337
5 (t_5)	Substation 200	+20	3357
6 (t_6)	New Substation 260	+20	3377
7 (t_7)	Substation 170	+20	3397
8 (t_8)	New Substation 250	+155	3552
9 (t_9)	Substation 150	+12	3564
10 (t_{10})	New Substation 260	+20	3584

Growth is forecast for 10 years ahead, for example using generating units under construction or planning. Beyond 10 years, growth trends are used because the evolution of the generating capacity is more uncertain than in the first 10-year horizon.

7.6.2 Fault Current Increase Analysis

The increase in fault currents through the studied breaker as a result of generation capacity growth is depicted in Figure 46, where fault current probability densities for each time interval are drawn with a vertical offset to show the expected evolution of maximum fault currents. The relative increases seem proportional to the additions to the generator fleet outlined in Table 15. In this particular case, the maximum fault currents through the studied breaker increase by 24 % (from 17.6 kA to 21.8 kA).

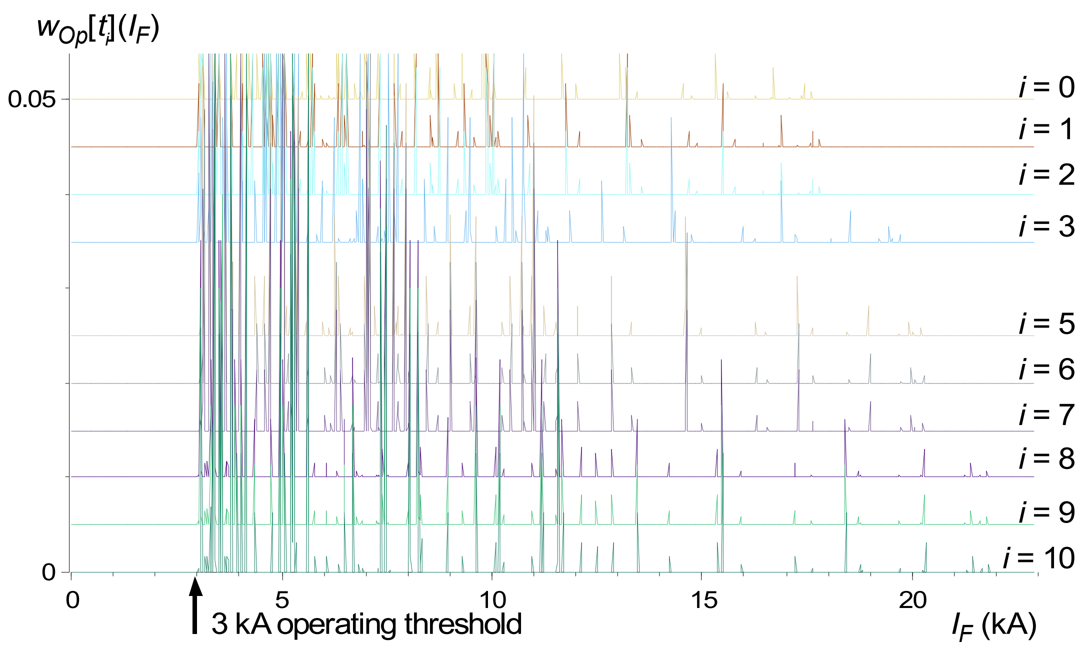


Figure 46: Evolution of statistical fault current levels for the studied breaker over the 10-year horizon.

7.6.3 Evolution of Breaker Duty and Interrupting Capabilities

7.6.3.1 Initial Breaker Ratings

Initial breaker ratings (breakers in new condition) are as follows: $I_0 = 12$ kA, $I_1 = 15$ kA, and $I_N = 12.5$ kA based on symmetrical RMS currents. Cumulated breaker duties are expressed in terms of asymmetrical fault currents. Assuming the contact parting time of all breakers is 2 cycles at 60 Hz, the X/R ratio is 17, and the relay response time is 0.5 cycles, it follows that the DC offset multiplier is 1.146, and the required asymmetrical interrupting capability is $I_{N,Asym} = 14.33$ kA. Then, from [37], $I_{Std} = 8I_{N,Asym} = 114.6$ kA.

When actual breaker ratings are not available from utilities or manufacturers (especially for the oldest devices), breaker ratings must be estimated. For illustrative purposes, the studied breaker is at half of its service life at the beginning of the scenario. In other words, the breaker is 20 years old at $t = t_0$, and its intended service life is 40 years. As a result, $I_{Cumul}(t_0) = I_{Std}/2 = 57.3$ kA. Using Equations (25) and (26), $I_0(0) = 11.7$ kA and $I_1(0) = 14.25$ kA.

7.6.3.2 Evolution of the Cumulated Duty

All lines are assumed to experience 10 faults per year per 100 miles, on average. Faults within a 70-mile radius around Substation 230 affect 319.3 miles of transmission lines. The corresponding number of faults interrupted by the considered breaker is $n_F = 31.93$ faults/year. The number of faults and the average duty in each $[t_i, t_{i+1}]$ time interval are shown in Table 16. The evolution of the cumulative duty is computed with respect to time using Equation (24) and is shown in Figure 47. Note that in Figure 47, one of the curves exhibits variations at discrete time intervals; the other curve interpolates the discrete curve and reflects a continuous variation of the plotted variables. The interpolation is computed by dividing the time horizon into weeks (years are marked as multiples of 52 weeks).

Table 16: Number of operations and cumulated duty for each discrete time interval.

Year i	$n_{Op,i}$ (until t_{i+1})	Average Duty (kA)	$I_{Op,i}$ (kA)
0 (t_0)	1.466321	5.615759	8.234508
1 (t_1)	1.500455	5.619918	8.432432
2 (t_2)	1.500455	5.620406	8.433164
3 (t_3)	1.535641	5.939203	9.120486
4 (t_4)	1.535641	5.939203	9.120486
5 (t_5)	1.538402	5.946327	9.326229
6 (t_6)	1.568114	5.955379	9.338715
7 (t_7)	1.568114	5.952926	9.334868
8 (t_8)	1.588805	6.197937	9.847312
9 (t_9)	1.588805	6.198219	9.847761
10 (t_{10})	1.588518	6.204240	9.855544

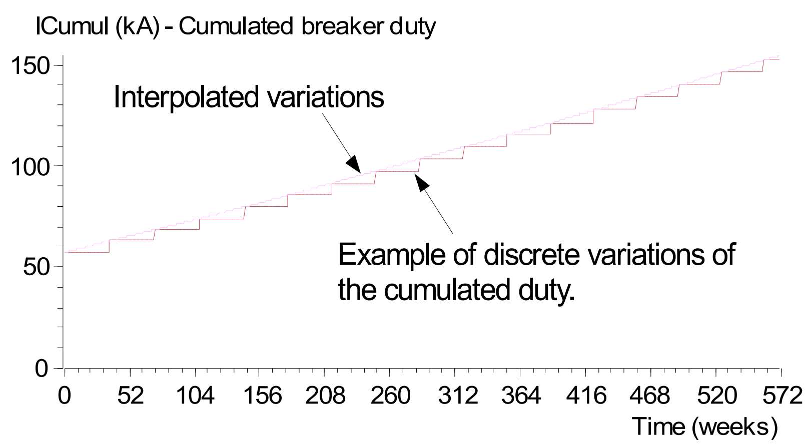


Figure 47: Expected evolution of the cumulative duty of Breaker 185.

7.6.3.3 *Evolution of the Interrupting Capability and Breaker Time-to-Failure*

The expected evolution of the interrupting capability thresholds I_0 and I_1 from Equations (25) and (26) is plotted in Figure 48. Both the discrete-time variation and the interpolation of the discrete data on a weekly basis are plotted in the figure. The interpolation of these variables is used in the rest of the computations.

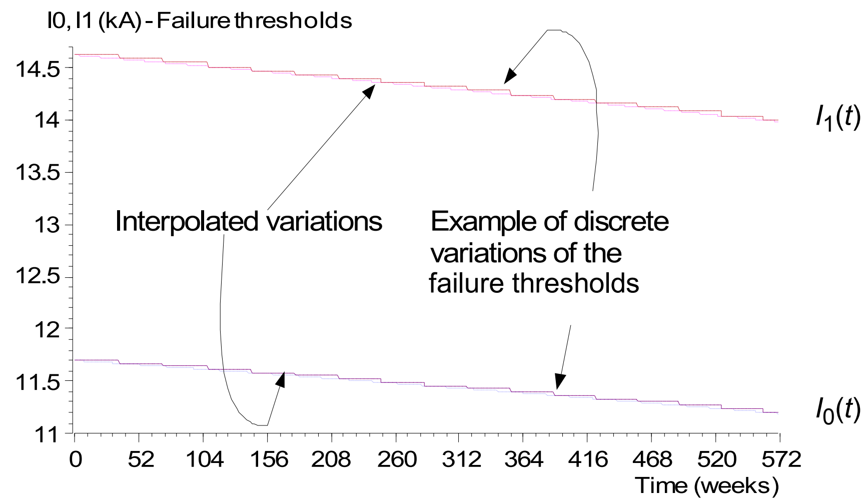


Figure 48: Expected evolution of the interrupting capability (failure thresholds) of Breaker 185.

As with the failure thresholds, the stress-induced probabilities of breaker failure also vary with time. The time horizon is discretized to a weekly scale as before, and the stress-induced probability of breaker failure is computed for each week using Equation (17). The expected variation of this probability is shown in Figure 49a. The stress-induced failure rate can be easily derived using Equation (18). Since $P_{Stress}(t)$ is much smaller than 1, $P_{Stress}(t)$ and $\lambda_{Stress}(t)$ have almost identical values.

The variation of the breaker MTTF from the contribution of fault stresses alone is then computed using Equation (39) and shown in Figure 49b. One can observe from Figure 49b that, when taken alone, the generation capacity growth scenario contributes to a reduction of the expected breaker lifetime by half. The importance of this impact is to be weighted with other general breaker reliability data.

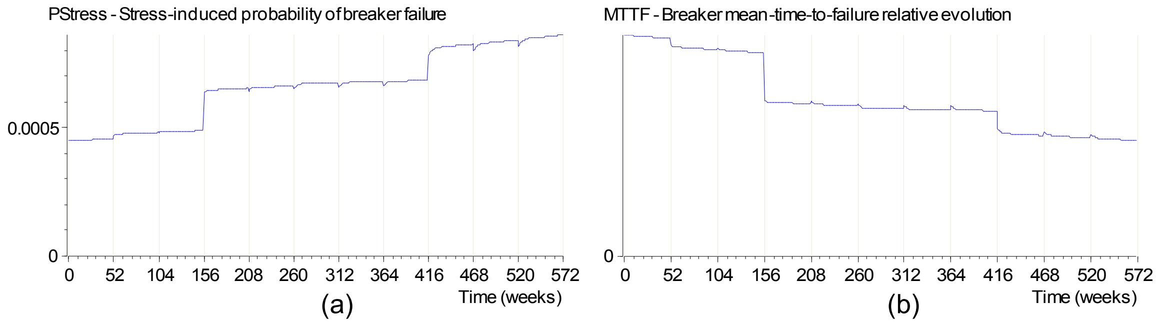


Figure 49: Evolution of (a) the probability of failure (one-year window) and (b) the MTTF of a breaker (relative scale).

The time horizon selected in this example is too short to provide enough stress information to predict the lifetime PDF of the breaker. The computation of such an estimate requires an extrapolation of the failure rates beyond the 10-year horizon described. In such extrapolations, failure rates may be inflated or deflated at the discretion of the utility or system operator. The failure rate function of this example can be approximated as

$$\lambda_{Stress}(t) = \lambda_{Stress}(0) + rt, \tag{43}$$

with t expressed in weeks from the present time.

In this example, using $\lambda_{Stress}(0) = 0.0004503416$ (starting value of the computed failure rates) and $r = 3 \times 10^{-7}$/week provides a trend that is comparable to the predicted values for $\lambda_{Stress}(t)$ (Figure 50). From this simplified expression of the stresses, and using Equation (39), the breaker lifetime PDF is

$$f_{MTTF}(t) = (\lambda_{Stress}(0) + rt)\ e^{-(\lambda_{Stress}(0)t + rt^2/2)}. \tag{44}$$

The lifetime PDF is also plotted in Figure 50. From here, the mean time-to-failure of the breaker is determined by taking the weighted average of the times with the values of the lifetime PDF. In this example, the MTTF of the breaker (from stresses only) is 1305 weeks or 25 years. For comparison, without the generation capacity increase, the expected MTTF would have been 2220 weeks under the conditions of this example and without considering aging factors.

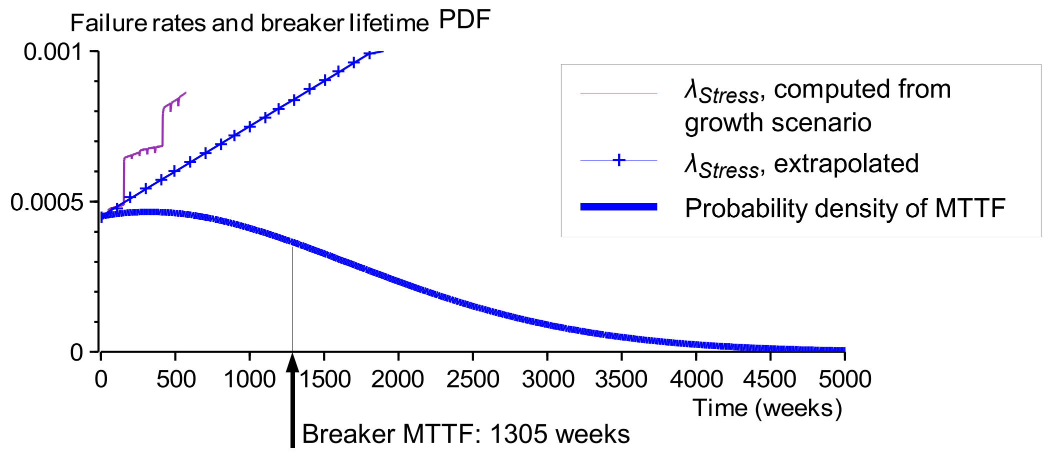


Figure 50: Example of extrapolated failure rates and circuit breaker lifetime PDF from the sole contribution of stresses.

7.7 Operation of Circuit Breakers in Sequence

In this section, the proposed algorithm to select which breakers to open is illustrated using one of the substations of the proposed test system. To simplify the illustration of the concepts introduced in earlier chapters, fault currents through each breaker of the substation are compared to the rating of that breaker. The same procedure can be completed using the low and high failure thresholds I_0 and I_1 introduced in Chapter 5.

7.7.1 Situation Overview

The focused substation in this example is Substation 230 with a fault between Phase A and the neutral on a bus inside the substation. A line between Substations 230 and 200 connects at this bus, and it is therefore faulted. The location of the fault and the RMS currents on Phase A drawn by the fault through each breaker of the substation and through connecting breakers at neighboring substations are shown in Figure 52. The identifying number and rating of each breaker is also shown in the figure for reference.

It is assumed that the relays can point to the exact fault location. To clear this fault while affecting the smallest area possible, Breakers 185 and 186 at Substation 230 and Breakers 158 and 159 at Substation 200 must operate.

7.7.2 Disadvantages of Basic Protection Schemes

Triggering Breakers 185 and 186 is not possible in the situation of this example because these two breakers are overstressed. These two breakers would fail if operated under the indicated fault currents. The same remarks also apply to Breakers 183 and 187. Overstress originates from the two connections to generating substations, through Breakers 195 and 196 that have been added without consideration of circuit breaker duty requirements.

Note that Breakers 195 and 196 are properly rated and can open on the fault currents indicated in the figure. In this example, this advantage can be leveraged to create temporary configurations that allow other breakers to switch and that otherwise would fail to clear faults.

To clear this fault while keeping overstressed breakers closed, the following breakers should be operated: 184, 187, 195, 89, 91, 97, 98, 158, 159, and 160.

Triggering all of these breakers may not be an acceptable practice to clear a single fault. First, power is removed from all transmission lines at Substation 230 but one. Basically, Substation 230 is almost isolated. The loss of power on these lines may affect neighboring substations and distribution systems as well. Worse, there is excess power produced by the three generators and the generating plant connected through Breaker 196; that surplus power is not balanced with a sufficient demand.

7.7.3 Temporary Substation Configurations and Switching Sequences

Based on the switching sequence algorithm proposed in Chapter 6, Breakers 195 and 196 should be open first because they do not belong to a ring. Fault analyses after opening these two breakers one after the other do not result in any of these breakers being overdutied. It remains necessary to open both Breakers 195 and 196 to reduce the duty of Breakers 185 and 186. If Breaker 195 (respectively 196) opens first,

- Breaker 185 must interrupt 17.6 kA (resp. 14.8 kA) but is rated for 14 kA.
- Breaker 186 must interrupt 28.3 kA (resp. 31.1 kA) but is rated for 16 kA.

Breakers 185 and 186 that are primary breakers for the spcified fault do not appear overdutied after the operation of Breakers 195 and 196. The fault current levels in this new configuration are similar to those before the addition of the new generating plants through Breakers 195 and 196. The fault currents through the rest of the breakers are shown in Table 17.

Breaker switching sequences must still be considered at this point because practically, breakers never open simultaneously. In contrast, as soon as one breaker in the ring of Substation 230 opens, the ring is broken, and some breakers may become overdutied again as a result of opening the first breaker. This point is illustrated in Figure 51 where the Phase A current through the breaker that remains closed jumps as the first breaker operates. There is clearly a partial transfer of fault duty as one breaker operates and opens the ring. In particular,

- if Breaker 186 opens first, Breaker 185 is overdutied with a duty of 25.5 kA.
- if Breaker 185 opens first, Breaker 186 is overdutied with a duty of 25.6 kA.

The point brought by the result above is that opening one of the Breakers 185 or 186 (primary breakers) after operating Breakers 195 and 196 results in the other primary breaker being overstressed. If a primary breaker operates, the other primary breaker cannot operate immediately after without failing and activating backup protection. As a result, the substation as a whole is considered before operating any breaker beyond Breakers 195 and 196, and a switching sequence must be considered to avoid breaker failures.

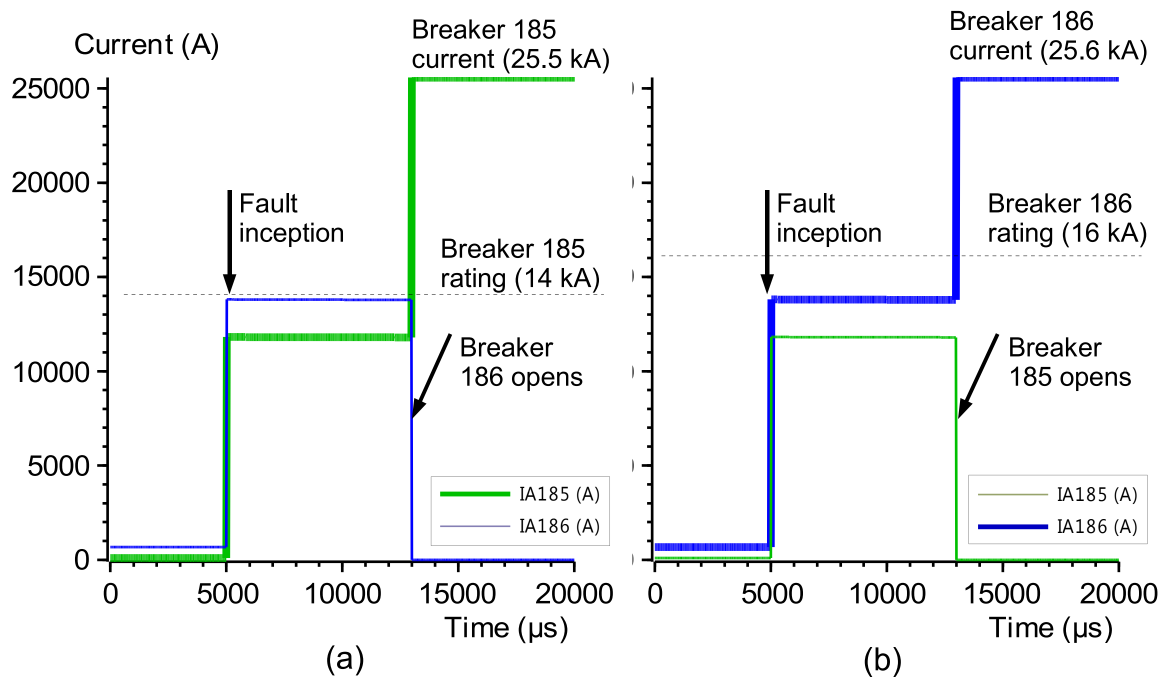


Figure 51: Plot illustrating the transfer of fault currents during a switching sequence, with (a) Breaker 186 opening first and (b) Breaker 185 opening first.

Table 17: Duties of circuit breakers at different switching stages at Substation 230. Scenarios involving overstressed breakers are highlighted.

ID	Breakers → (kA rating) ↓ Switching sequences	183 (16)	184 (20)	185 (14)	186 (16)	187 (20)	191 (10)	192 (10)
1	All closed	$\boxed{18.79}$	17.57	$\boxed{20.41}$	$\boxed{45.22}$	$\boxed{23.88}$	9.44	3.114
2	195	$\boxed{16.00}$	14.76	$\boxed{17.64}$	$\boxed{28.25}$	$\boxed{26.96}$	6.68	1.00
3	196	13.14	11.89	$\boxed{14.79}$	$\boxed{31.13}$	9.86	3.75	2.76
4	195, 196	10.12	8.83	11.84	13.81	12.48	1.01	5.40
5	195, 196, 183	open	1.34	1.76	$\boxed{23.93}$	$\boxed{22.60}$	9.23	$\boxed{15.51}$
6	195, 196, 184	1.34	open	3.10	$\boxed{22.64}$	$\boxed{21.31}$	7.93	$\boxed{14.22}$
7	195, 196, 185	1.76	3.10	open	$\boxed{25.64}$	$\boxed{24.31}$	$\boxed{10.97}$	$\boxed{17.24}$
8	195, 196, 186	$\boxed{23.93}$	$\boxed{22.64}$	$\boxed{25.64}$	open	1.33	$\boxed{14.73}$	8.44
9	195, 196, 187	$\boxed{22.60}$	$\boxed{21.31}$	$\boxed{24.31}$	1.33	open	$\boxed{13.40}$	7.11
10	195, 196, 191	9.23	7.93	10.97	14.73	13.40	open	6.29
11	195, 196, 192	15.51	14.22	$\boxed{17.24}$	8.44	7.11	6.29	open
12	195, 196, 191, 185	0.17	0.36	open	14.68	13.38	open	6.26
13	195, 196, 191, 186	9.16	7.88	10.85	open	2.73	open	1.2
14	Fault cleared	0.66	1.24	open	open	0.90	0.87	0.66

Breakers 185 and 186 belong to the same loop comprised of Breakers 183, 184, 185, 186, 187, 191, and 192. It is clear from Table 17 that breaking the ring by opening the primary breakers, Breaker 185 or 186, or their immediate neighbors makes either Breaker 185 or 186 overstressed. Trying to reduce fault currents on Breaker 185 or 186 alone makes the fault clearing process complicated by involving most of the breakers of Substation 230 and neighboring substations.

The only possibility of breaking the ring without overdutying Breakers 185 and 186 in this case is to open Breaker 191, as shown in Cases 12 and 13 of Table 17. By opening Breaker 191, fault currents from the generators are divided more evenly between Breakers 185 and 186 than in other scenarios. Also, Breakers 185 and 186 can be both open, regardless of order, after operating Breaker 191. Breakers 158 and

159 are open last to completely isolate the fault.

A summary of the switching sequence is depicted graphically in Figures 52, 53, 54, and 55.

A quasistatic simulation of RMS currents (evolution of RMS values with time) through Breakers 185, 186, and 191 during the switching sequence is also completed to confirm the intended transfers of breaker fault currents. The Phase A breaker currents are shown in Figure 56. (The system is rescaled when converted from a load flow to a quasistatic model. As a result, the computed currents in the power flow fault analysis and in the quasistatic analysis are different.)

If the considered fault occurs frequently, the substation ring may be opened permanently, and Breaker 191 can be left open to avoid repeated switching of substation configurations. By breaking the ring, fault currents through Breakers 185 and 186 are kept under control. The risk of this approach is an outage of the entire substation if the breakers that remain closed fail for any reason.

7.8 Remedial Actions on Generator Dispatch

As mentioned in Section 6.4, adjustments to the economic dispatch are best applied to new generating plants connected to the network because the output of these plants increases gradually to follow the growth of the system.

Substations 230-A and 230-C are immediate neighbors of Substation 230. Adjustments to how many generators are connected in either Substation 230-A or 230-C affects fault currents through the breakers of Substation 230. For reference, generators in Substations 230-A and 230-C are numbered G1, G2, G3, and G4 (Figure 43). Generator G1 is required to be operational because it is the PV generator in each of these two substations. In Substation 230, which is also a generator substation, disconnecting one or more generators affects fault currents through the breakers of the substation.

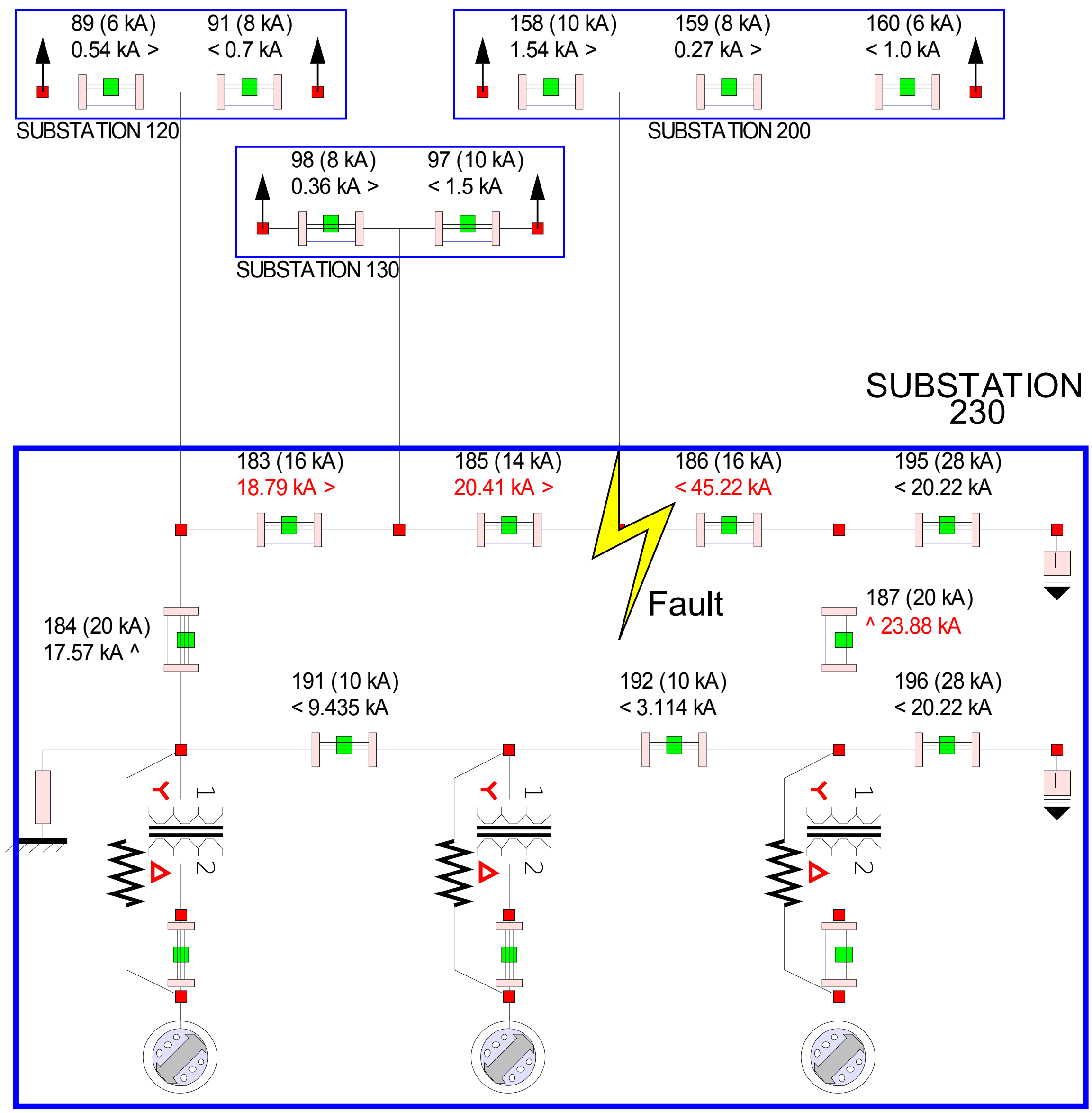


Figure 52: Fault currents compared to breaker ratings at Substation 230 and neighboring substations.

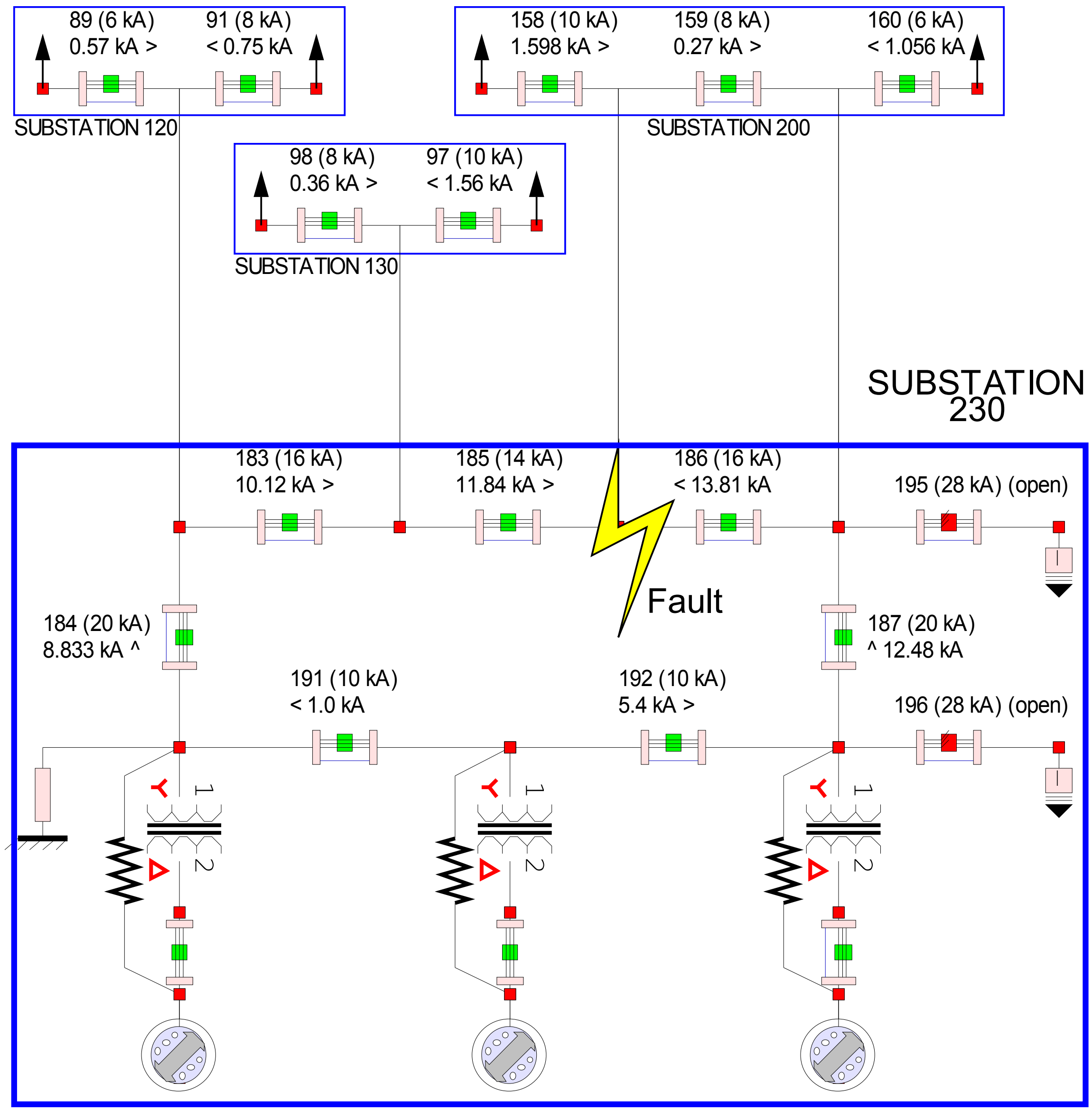


Figure 53: Circuit breaker fault currents after opening Breakers 195 and 196 at Substation 230.

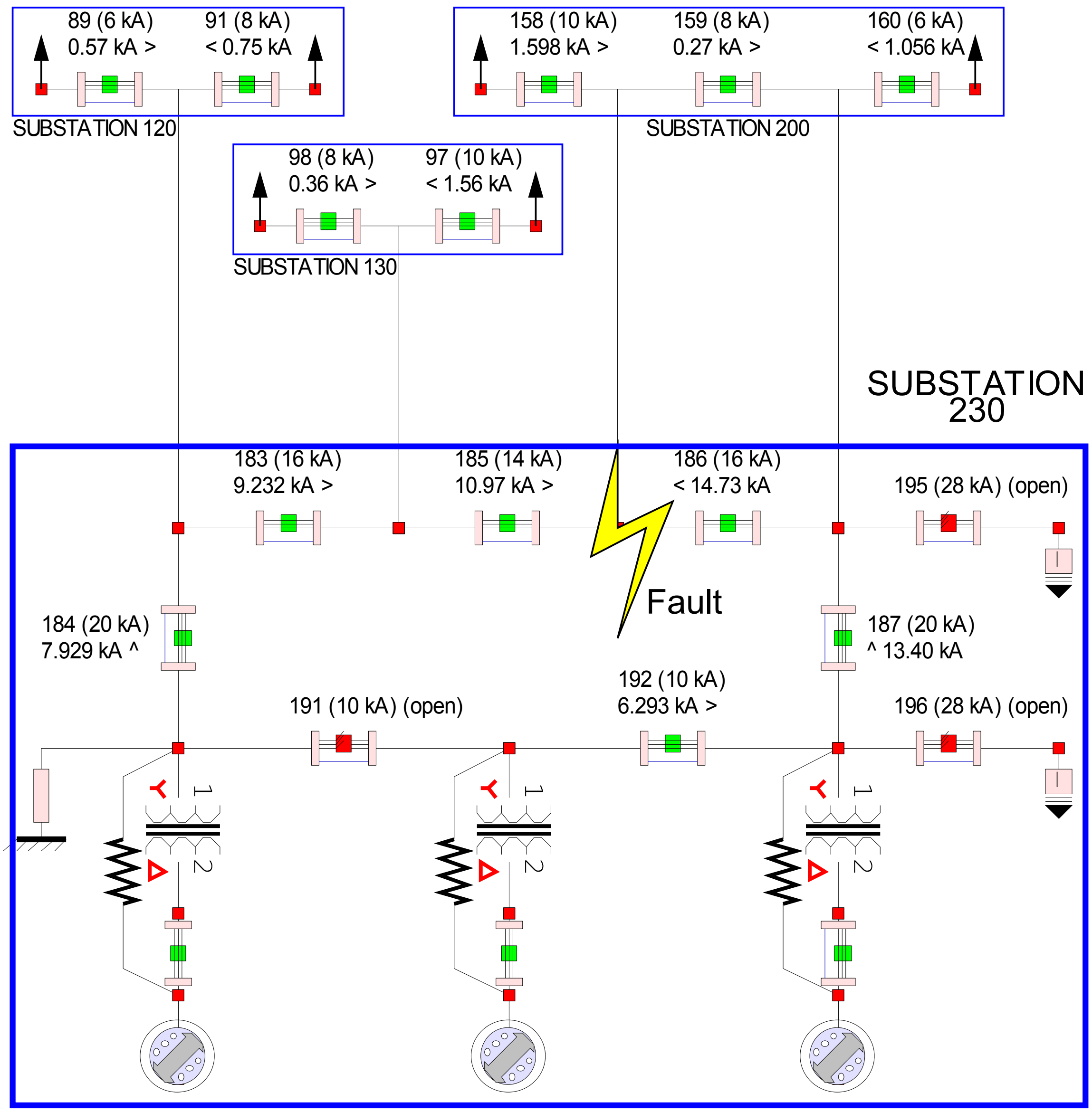


Figure 54: Circuit breaker fault currents after opening Breakers 195, 196, and 191 at Substation 230.

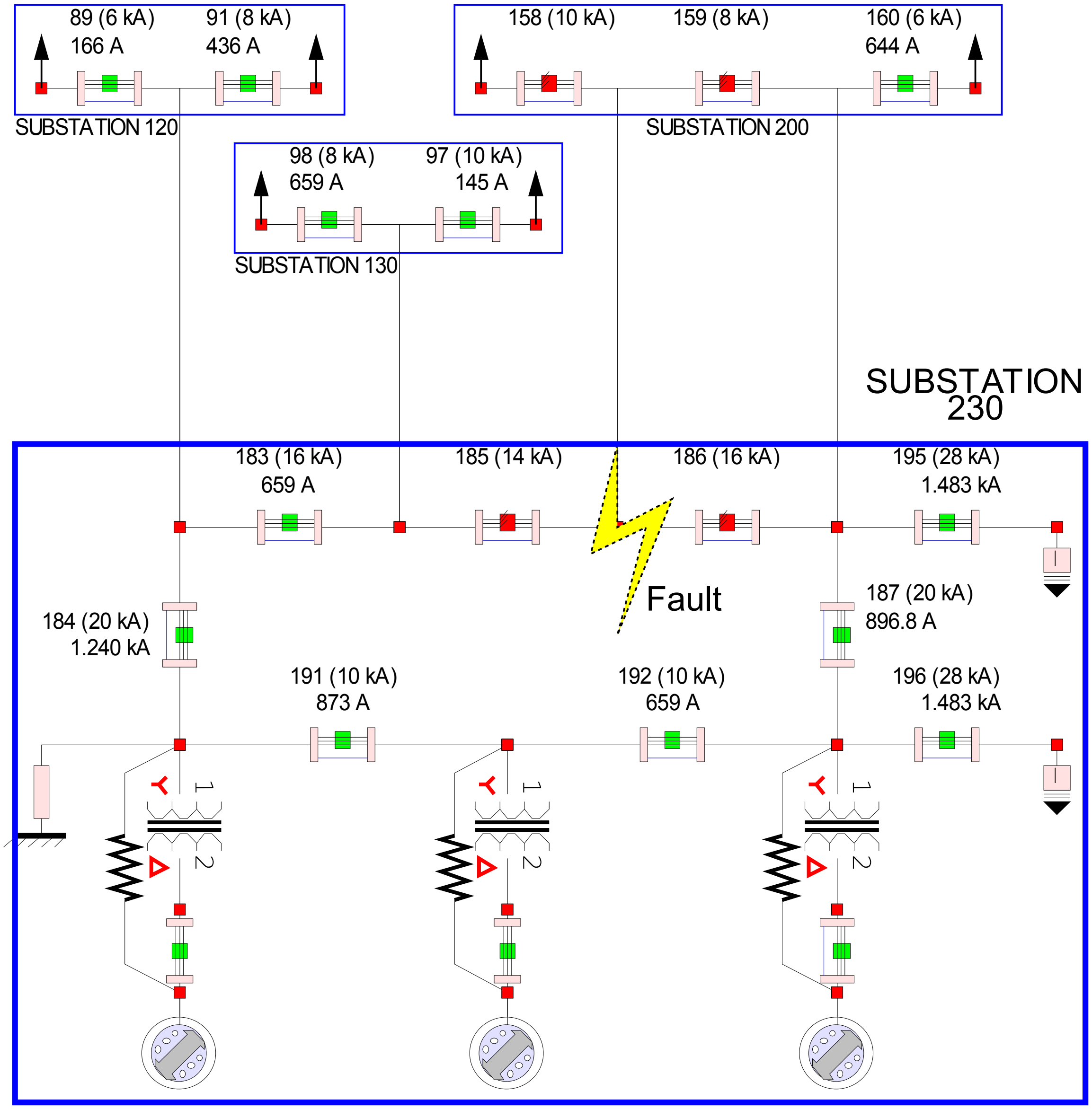


Figure 55: Circuit breaker currents after clearing the fault at Substation 230.

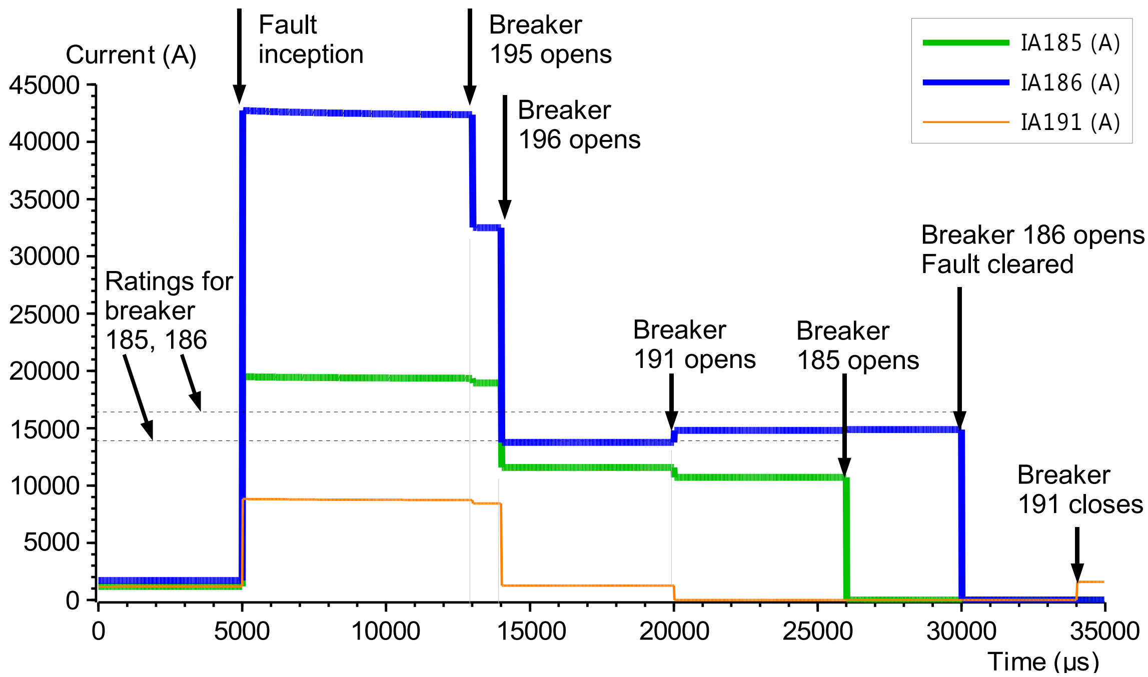


Figure 56: Quasistatic plots of circuit breaker currents during the switching sequence.

In Section 7.7, it is established that removing the connection to Substations 230-A and 230-C, i.e. opening Breakers 195 and 196 reduces fault currents through the breakers throughout the entire substation.

The studied fault is the same as the example in the previous section, i.e. a fault between Breakers 185 and 186. All breakers in Substation 230 are open. An additional constraint is added: generator G1 must be connected in Substations 230-A and 230-C for PV control. In other words, at least one generator must be active at Substations 230-A and 230-C. The economic dispatch for Substations 230, 230-A, and 230-C addresses two issues:

- Is it possible to operate the generators at these substations without overdutying circuit breakers for the specified fault?

- If all loads were to be served, what would be the failure rates of the circuit breakers?

Table 18: Duties of circuit breakers at Substation 230 for different generator commitments. Scenarios involving overstressed breakers are highlighted.

ID	Breakers → (kA rating) ↓ Generator constraints	183 (16)	184 (20)	185 (14)	186 (16)	187 (20)	191 (10)	192 (10)
1	Initial case (+1240 MW)	$\boxed{18.79}$	17.57	$\boxed{20.41}$	$\boxed{45.22}$	$\boxed{23.88}$	9.44	3.11
2	Sub. 230-A with G1 only (+775 MW)	15.72	14.46	$\boxed{17.42}$	$\boxed{37.81}$	16.52	6.58	1.17
3	Sub. 230-A and 230-C with G1 only (+310 MW)	11.76	10.41	13.61	$\boxed{21.05}$	14.75	3.13	3.24
4	Same as above + Sub. 230 with G2 removed (+155 MW)	9.26	7.89	11.15	$\boxed{17.78}$	11.45	1.17	1.11
5	Same as above + Sub. 230 with G1 removed (+0 MW)	5.31	3.96	7.24	14.81	8.46	3.58	3.34

Different scenarios are tested and the results are summarized in Table 18. In parentheses are indicated the difference between and the connected capacity before the addition of substations 230-A and 230-C. These scenarios are also illustrated in points (a), (b), (c), and (d) of Figure 57.

In terms of operating breakers within their ratings, reducing the generating capacity to its level before the addition of Substations 230-A and 230-C reduces the duty on primary breakers for the specified fault at Substation 230, similarly to Case 4 in Table 17. Relocation of generation sources has a minor effect on fault currents as the results from Table 18 and Table 17 differ slightly. With fault currents through circuit breakers reduced, a switching sequence can be found to clear the specified fault and preserve breaker adequacy.

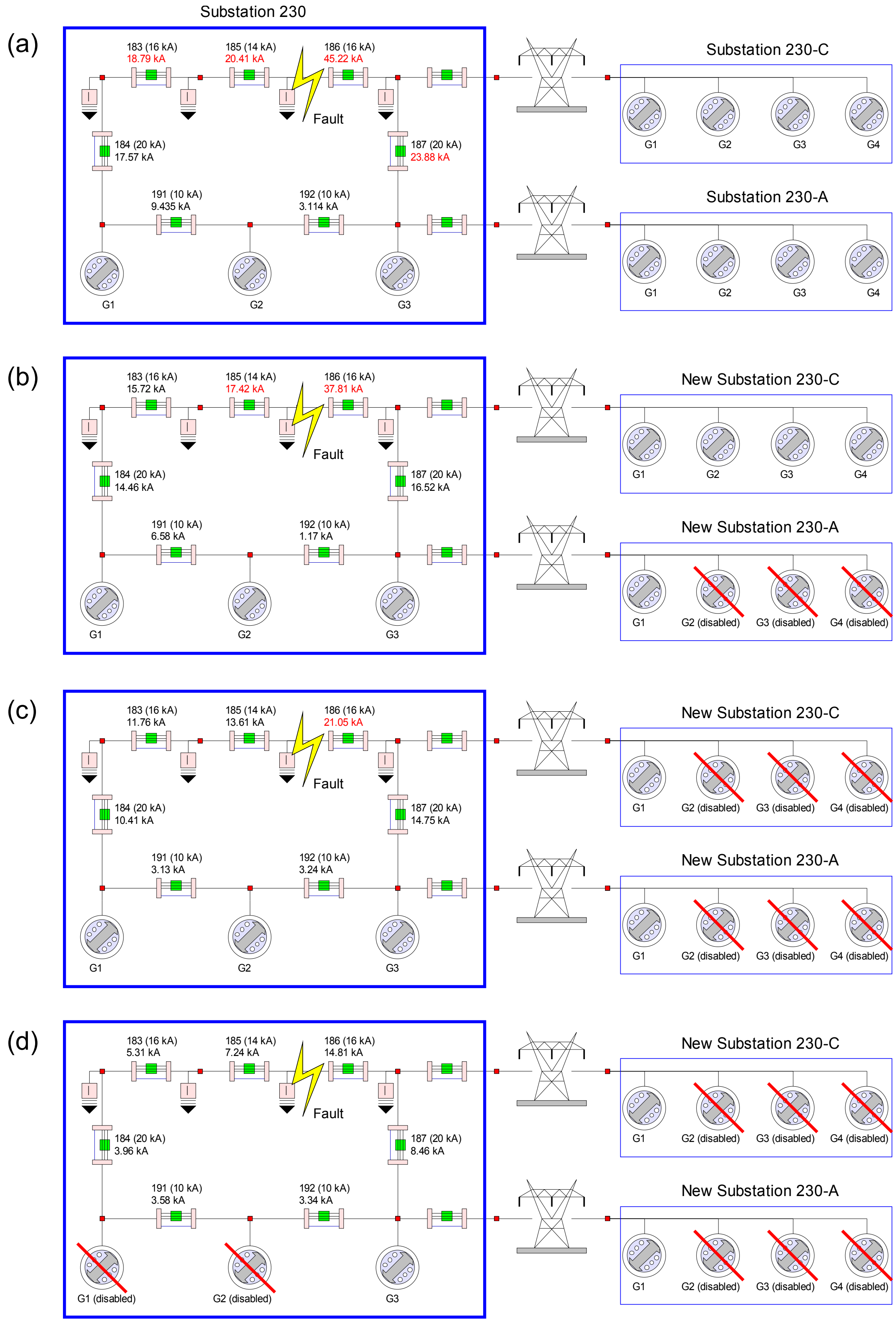


Figure 57: Circuit breaker currents at each stage of the generator dispatch adjustment.

In terms of serving all load, assuming loads have grown by less than 155 MW from the commissioning of generators, Case 4 in Table 18 is equivalent to an addition of 155 MW to the capacity to before the commissioning of Substations 230-A and 230-C. From the fault analysis on this case, only one breaker (Breaker 186) is overdutied after applying the generator disptch solution. A proper switching sequence (or other actions) must be found to clear the fault between Breakers 185 and 186 without breaker failures.

7.9 Integrating Current Limiting Devices

In Figure 58, a fault current limiter is inserted in series with Breaker 186 to reduce the fault duty of that breaker. The equivalent, positive sequence circuit of the current limiter is shown in Figure 59.

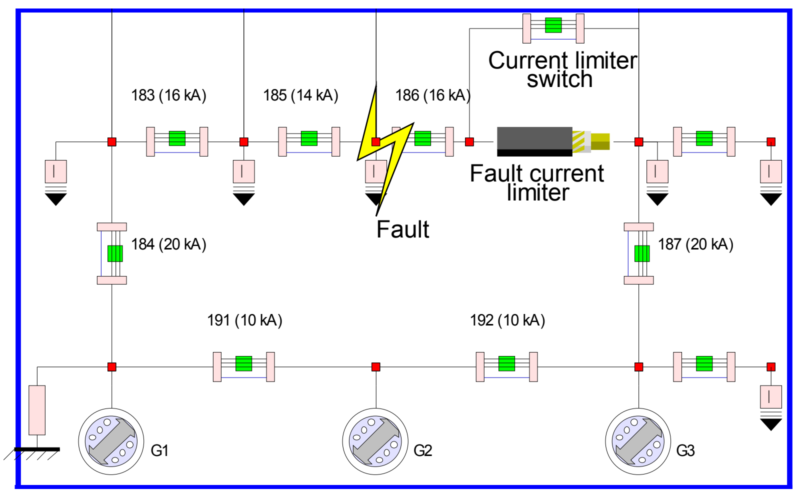


Figure 58: Diagram of Substation 230 with current limiting device in series with Breaker 186.

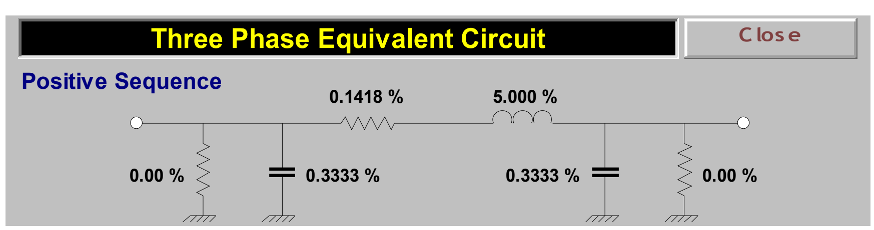


Figure 59: Positive sequence circuit of the current limiter from Figure 58.

As in the switching sequence previously described, a single-line-to-neutral fault is applied between Breakers 185 and 186. As in the switching sequence example, fault currents through Breakers 185 and 186 are initially reduced by opening Breakers 195 and 196. To clear the fault, Breaker 185 is opened first. Breaker 186 receives the portion of the fault current that was flowing through Breaker 185 and becomes overstressed. To further reduce the duty through Breaker 186, a fault current limiter is activated. Fault clearance is completed when currents through Breaker 186 fall below the rating of the breaker and Breaker 186 operates. The evolution of breaker currents are plotted in Figure 60.

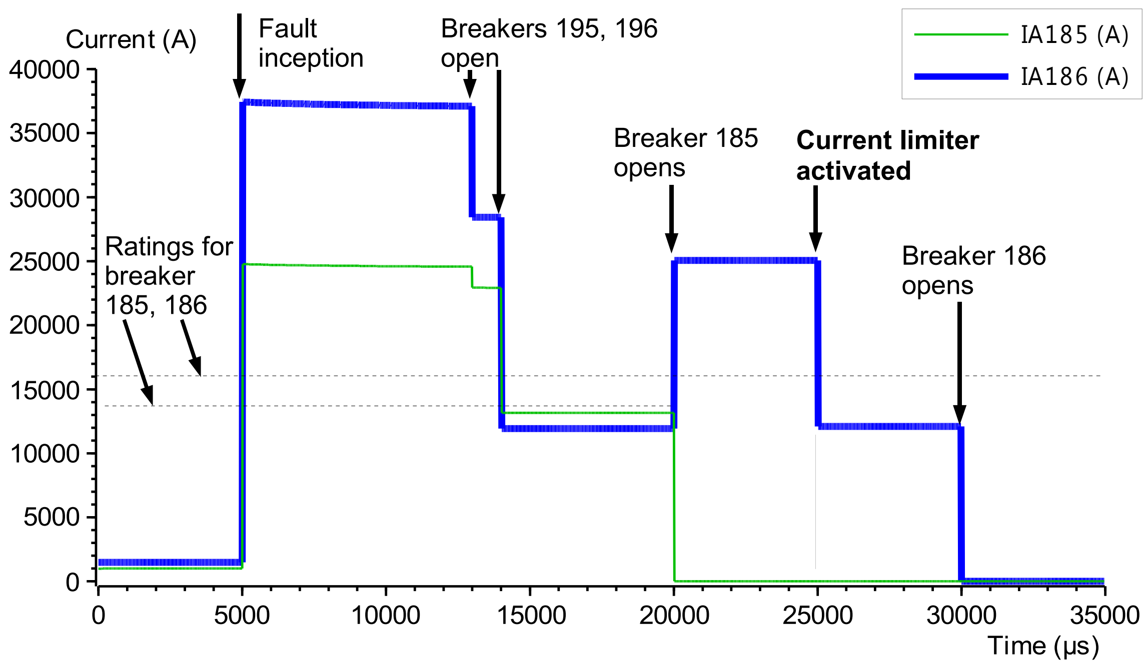


Figure 60: Quasistatic plot illustrating the effect of a current limiting device on breaker RMS currents.

Current limiters are effective at bringing fault currents to levels that are much lower than the ratings of the breakers. Their use is still not widespread because of the insufficient maturity and the relatively high cost of current limiters. Nonetheless, overstressed breakers directly benefit from fault current limiters in terms of avoided failures.

7.10 *Directions for Future Developments*

7.10.1 Real-Time, Accurate Model of Breaker Fault Duty

In an electrical network, circuit breaker stresses change each time the topology of the network is modified. The simulation software used, WinIGS, performs fault analysis for one breaker at a time, for a given topology, and for a specific type of faults. Should the topology of a substation change, the fault duty analysis must be completed again for each breaker of the network using the new topology.

Optimizing substation connectivity to prevent breaker failures requires the examination of numerous possible connectivity schemes. One of the first tasks for future work is to create an algorithm that recomputes the duty of every breaker for the considered connectivity schemes. The WinIGS software can be automated by launching several simulations one after the other for each breaker, with all fault types associated with the appropriate likelihood.

Besides simulation automation, the precision and meaning of the reliability quantities produced, such as P_{Stress}, must be matched with field observations. Field data are usually available from utilities. On the data precision aspect, the figures for probabilities may vary depending on the resolution selected to compute the fault currents density functions. To avoid discrepancies, the reliability data must be computed and compared on the same fault current resolution.

7.10.2 Presentation of Circuit Breaker Data as a Control Center Application

Stress-induced breaker failures and other breaker reliability data can be graphically rendered to provide with a quick but comprehensive view of the conditions of all circuit breakers in a power system to system operators. A conceptual example of such a color-sensitive display is shown in Figure 61. The display has the following characteristics:

- Use of a breaker-oriented network diagram;
- Flattened network diagram to have all substation layouts available in the same display; and
- Breaker data are drawn as bars shown at the location of the breakers.

Colors may be used to distinguish breaker duty status. In Figure 61, green bars indicate acceptable failure rates, and overflowing red bars indicate failure rates exceeding an acceptable value (set at 10^{-4} in this example). The network diagram in the background is the 24-bus system diagram with all substation breakers as it appears in the 1996 definition of the IEEE Reliability Test System.

If working at the substation level rather than the system level, the display described above can be limited to a particular substation or a specific path within a substation.

Circuit breaker reliability data monitoring applies not only to individual breakers within substations, but also to all the possible paths that connect any two points within the substation. At the substation level, the display of circuit breaker reliability data (Figure 62) can be applied to the selection of the most reliable substation paths to connect two lines together (Figure 63). A simple path enumeration algorithm is utilized that converts a graph between two substation nodes into a list of paths between these two nodes. As an example, the stress-induced failure probabilities of a path is computed using

$$P_{Stress,Path} = 1 - \prod_{k \in Path} (1 - P_{Stress,k}),$$

where k denotes the index of each breaker within the selected path.

Of course, as a control center application, all breaker data (including reliability data) are concentrated in one database that allows retrieving and comparing specific quantities side by side for all the breakers in the system (Figure 64).

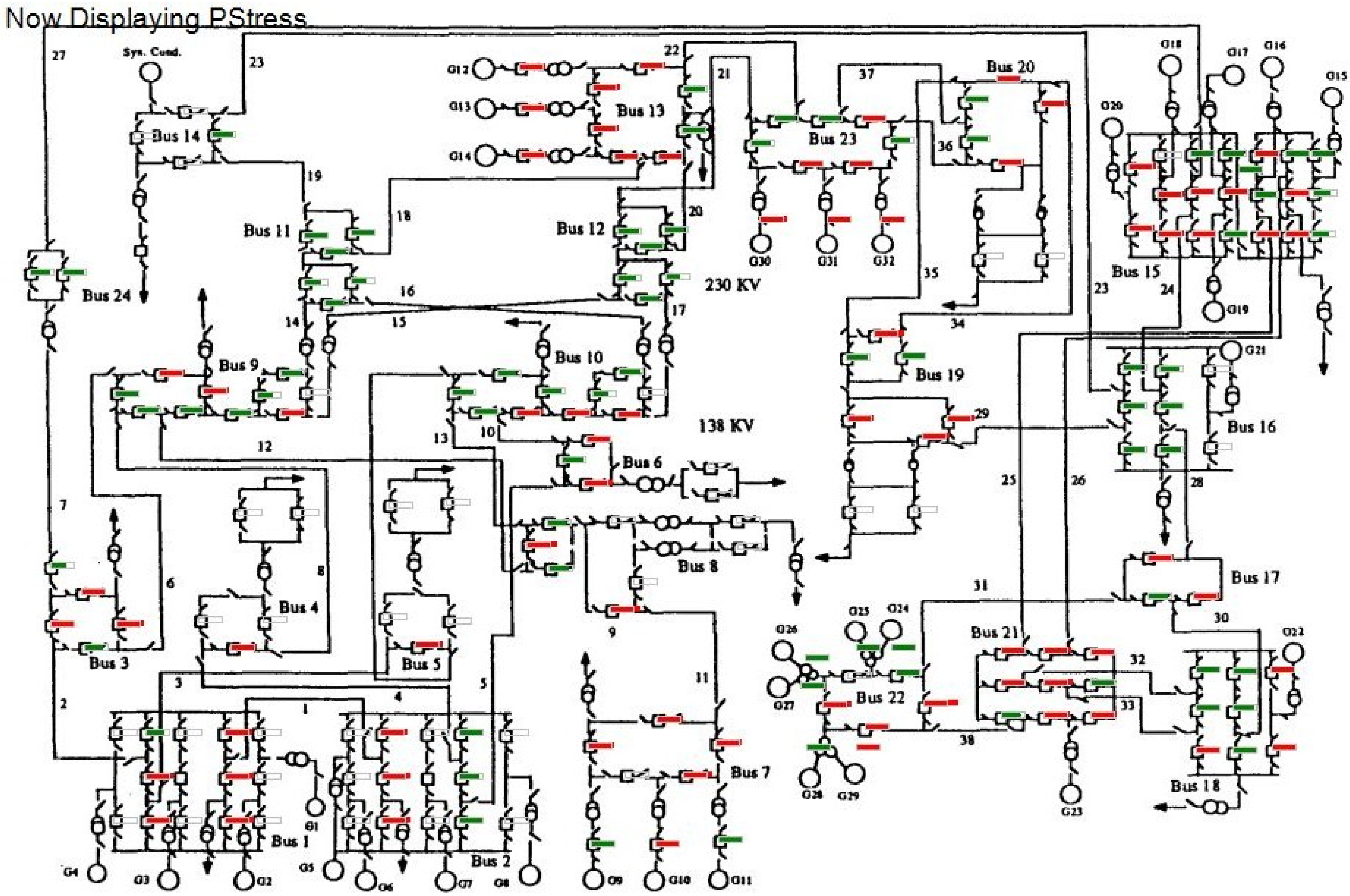


Figure 61: Example of system-wide visualization of P_{Stress} using colored bars for all breakers.

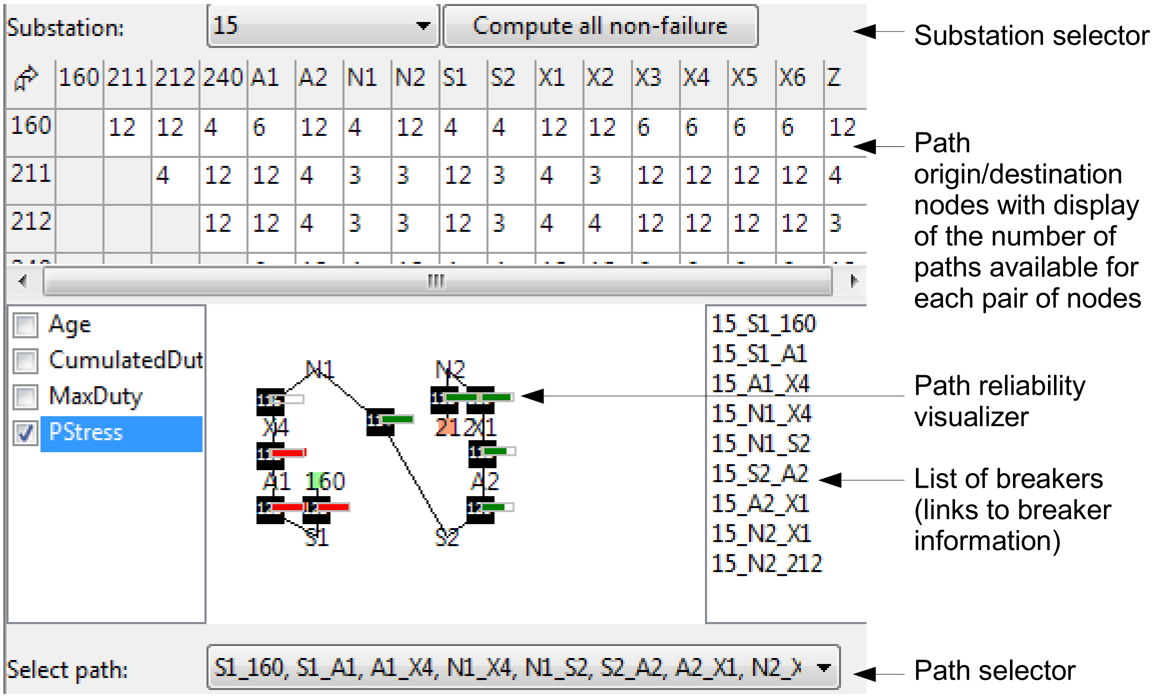
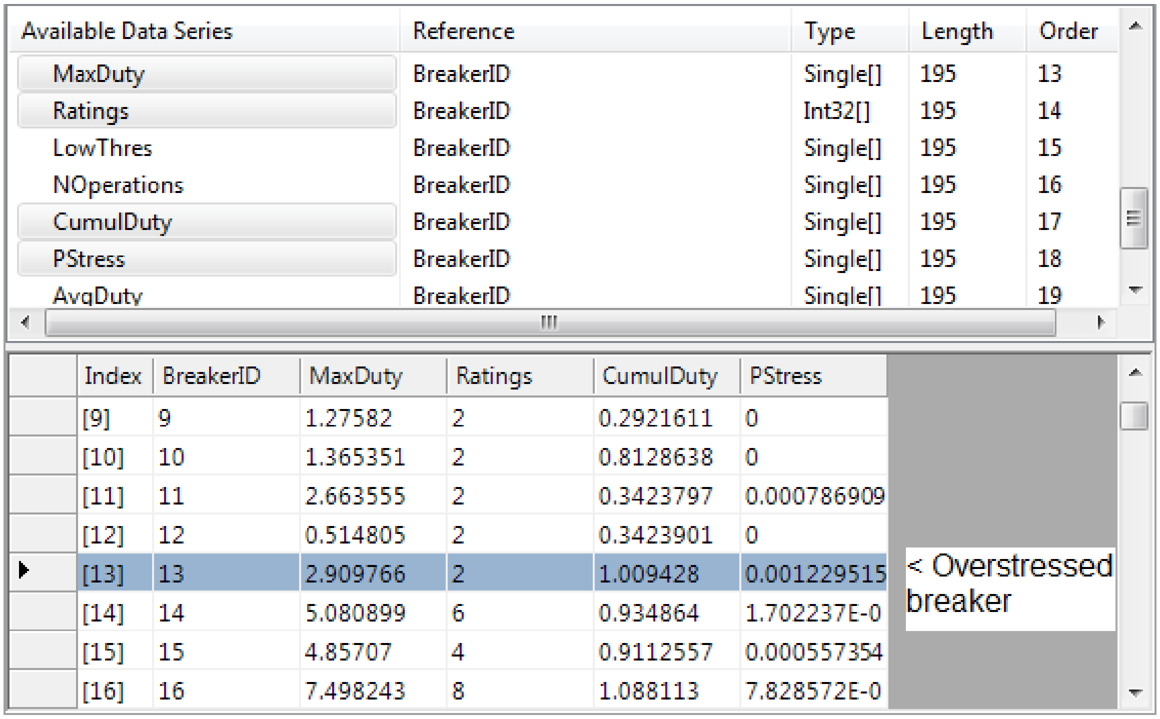


Figure 62: Example visualization of breaker reliability data for a substation path.

Path ID	Probability of Non-failure	Remarks
1	0.99982941	170 to 211 via 170_A1, N_A1, N_211,
2	0.99930819	170 to 211 via 170_A1, N_A1, N_H, H_Z, 212_Z, 211_212,
3	0.99966069	170 to 211 via 170_Z, 212_Z, 211_212,
4	0.99950571	170 to 211 via 170_Z, H_Z, N_H, N_211,
5	0.99974417	170 to 212 via 170_A1, N_A1, N_211, 211_212,
6	0.99939339	170 to 212 via 170_A1, N_A1, N_H, H_Z, 212_Z,
7	0.99974592	170 to 212 via 170_Z, 212_Z,
8	0.99942050	170 to 212 via 170_Z, H_Z, N_H, N_211, 211_212,
9	0.99996225	170 to A1 via 170_A1,
10	0.99952790	170 to A1 via 170_Z, 212_Z, 211_212, N_211, N_A1,
11	0.99951419	170 to A1 via 170_Z, H_Z, N_H, N_A1,
12	0.99942342	170 to H via 170_A1, N_A1, N_211, 211_212, 212_Z, H_Z,
13	0.99971413	170 to H via 170_A1, N_A1, N_H,

Figure 63: Example report of substation path reliability calculations.



Available Data Series	Reference	Type	Length	Order
MaxDuty	BreakerID	Single[]	195	13
Ratings	BreakerID	Int32[]	195	14
LowThres	BreakerID	Single[]	195	15
NOperations	BreakerID	Single[]	195	16
CumulDuty	BreakerID	Single[]	195	17
PStress	BreakerID	Single[]	195	18
AvgDuty	BreakerID	Single[]	195	19

Index	BreakerID	MaxDuty	Ratings	CumulDuty	PStress
[9]	9	1.27582	2	0.2921611	0
[10]	10	1.365351	2	0.8128638	0
[11]	11	2.663555	2	0.3423797	0.000786909
[12]	12	0.514805	2	0.3423901	0
[13]	13	2.909766	2	1.009428	0.001229515
[14]	14	5.080899	6	0.934864	1.702237E-0
[15]	15	4.85707	4	0.9112557	0.000557354
[16]	16	7.498243	8	1.088113	7.828572E-0

< Overstressed breaker

Figure 64: Tabular display of circuit breaker reliability data.

The tools and displays described can be integrated into a single control center software focused on circuit breaker adequacy analysis. The prospective software uses a real-time model of power systems. Every time the topology of the controlled network changes for continued operation (as opposed to transient response), the fault and reliability data for the appropriate breakers are recomputed using the procedure described in this study. Protection schemes that account for circuit breaker adequacy can be designed and tested offline using the available circuit breaker data. Should a fault cause currents to exceed the ratings of a breaker, protection schemes with focus on breaker adequacy can help avoid breaker failures and extended common-mode outages.

7.10.3 Applications to Power System Reliability Analysis

In the case of a breaker failure, backup protection schemes isolate the fault by opening breakers surrounding the faulted area. The affected area grows until fault conditions are cleared, and the response of backup protection systems results in simultaneous, multiple component outages.

The results of the analysis of circuit breaker failures caused by short-circuit currents above nameplate rating can serve as inputs to bulk power system reliability analysis methodologies such as one recently published [41]. The bulk power system reliability analysis methodology is based on selective enumeration of contingencies. The common-mode outages resulting from the proposed methodology can be incorporated in the reliability analysis as a means to improve the selection or ranking of the contingencies.

The effects of common-mode outages on the overall system reliability still have to be determined. The proposed circuit breaker reliability model allows the computation of better data for reliability assessment methodologies.

7.11 Summary

The numerical examples presented in this chapter present circuit breaker reliability results from fault analysis using a 24-substation test system derived from the IEEE Reliability Test System. The modified test system is a three-phase, breaker-oriented, physical model of a transmission network with explicit modeling of breaker arrangements at all substations. The test system also uses three-phase, physical models of transmission lines and cables for improved fidelity with existing networks.

A quantification of the factors (system and simulation) that affect the range and probability density of fault currents is presented. Such factors include the fault types considered (one, two, and three phases affected) The impact of these factors on the reliability of the considered circuit breakers must not be neglected.

The impact of the growth of power systems is also considered using a case where breaker failure rates are updated as the generation capacity of the test system is expanded with power plants of different sizes.

Besides, operating strategies are explored using fault conditions involving the operation of overdutied breakers. Operation of breakers in sequence, adjustments to generator dispatch, and the use of fault current limiters are short-term solutions to the breaker overstress problem. Particular attention must be given to the transfer of fault currents to a single breaker when clearing a fault on a ring bus. Long term solutions involve the upgrade or replacement of overstressed breakers, or an overhaul of protection schemes.

Possible immediate applications of breaker adequacy analysis are presented, with an emphasis on control center applications. In control centers, operators are provided with displays that convey a picture of the overall condition of the system at a glance. As an extension of this study, the circuit breaker reliability quantities computed from breaker fault statistics can be integrated in more comprehensive models to study common-mode outages and their impact on overall system reliability.

CHAPTER VIII

CONCLUSION

8.1 Review of Contributions

Power systems grow as the demand for reliable electric power increases. New power sources such as large plants (e.g. nuclear reactors, natural gas plants, etc.) and distributed generation (including wind and solar farms, small non-utility generators, and cogenerating facilities) are gradually added to power systems to meet the growing demand.

Additions to the generation capacity of a network cause fault currents to increase. These additions may result in operational unreliability because as fault currents increase, fault currents will eventually exceed circuit breaker ratings. Specifically, circuit breakers are more likely to fail when fault currents gradually reach and exceed breaker interrupting capabilities. Meanwhile, power system operations must continue at acceptable reliability levels.

The contributions of this research are (a) a methodology to quantify breaker failures caused by increased fault stresses as the generation capacity of power systems expands and (b) operational strategies that address circuit breaker adequacy issues. Because the underlying phenomena are dependent on uncertain parameters, probabilistic approaches are employed. The developed methodology and operational strategies are based on four contributed models described below.

Probability Density Computation of Fault Currents To quantify stress-induced breaker failures, a methodology that employs a Monte Carlo simulation of fault currents through the considered breakers and that is based on three-phase, breaker-oriented, physical models of power networks is proposed [159]. Circuit breaker arrangements are modeled explicitly to allow fault analysis at the circuit breaker level. A three-phase, breaker-oriented fault analysis procedure is used to determine breaker fault current statistics [160]. The Monte Carlo simulation itself is based on a known average number of faults per year on each transmission line of a test system.

Circuit Breaker Reliability Model The probability density functions of fault currents obtained from the Monte Carlo simulations are combined with interrupting capability functions that determine, for each considered breaker, the probability of success or failure of a breaker operation for currents of a given magnitude. The combination of the probability density of fault current levels and the interrupting capability function, in conjunction with the expected number of operations of a circuit breaker during a particular time period, provides the probability of breaker failure as a result of fault stresses [161, 162, 163].

Prediction of the Evolution of Breaker Failure Data To help estimate the time-to-failure of a breaker, the stress-induced probability of failure obtained for that breaker is factored into a Markov chain [164]. The time dimension of circuit breaker failures is provided by a generation growth model over a given time horizon. The generation growth scenario is the starting point to predict the evolution of the breaker time-to-failure over the considered time horizon. Because generation growth impacts circuit breaker failure rates, periodical updates of circuit breaker reliability data are highly desirable.

Substation Reconfiguration and Economic Dispatch Constrained by Breaker Reliability The computed circuit breaker failure data and operating limits become constraints for power systems operation and protection. Several strategies to circumvent circuit breaker adequacy constraints are explored. Fault current limiters appear as the least invasive (but most expensive) solution to reduce the duty of overstressed breakers. Operating substation breakers in sequence carries the benefit of controlling the flow of fault currents through all breakers. An algorithm to find such a sequence with an account for breaker ratings and stresses is proposed. The inclusion of circuit breaker reliability constraints into the optimal power flow or the economic dispatch problems tackles the issue of breaker adequacy at its source by restricting generating capacity and fault currents. With such strategies, system reliability can be maintained while delaying the need to upgrade breakers until the proper time.

8.2 Directions for Future Work

The two most important perspectives discussed in this section are the calibration and validation of the proposed model and the deployment of the proposed methodologies in substations and control centers.

8.2.1 Model Integration and Result Validation

The proposed circuit breaker reliability model is focused on the contributions of fault currents to the breaker failure rates, independently from the contributions of aging. Ultimately, the proposed circuit breaker reliability model must include all failure rates from all breaker failure modes, especially aging and stresses.

The models and illustrative results presented in this thesis must be calibrated and validated, ideally against utility records, manufacturer designs, and breaker test results. One area for improvement is the accuracy of the Monte Carlo simulation of fault currents, where the simulation of different types of faults with different likelihoods on different lines can be automated. In addition, the relative importance of age-related failures and stress-related failures must be determined for the different stages of the life of a circuit breaker. Predictions of the breaker time-to-failure should also account for trends in generation growth and are best performed with growth scenarios that are consistent with the expansion history of existing infrastructure from different utilities.

8.2.2 Deployment to Substations and Control Centers

The proposed methodologies for economic dispatch and substation reconfiguration can be developed and implemented as new applications for control centers and substation protection schemes. In particular, updates of the fault current statistics as the configuration of the studied power system changes provide a global vision of circuit breaker adequacy issues to the operators and protection systems. As a result, the methodologies proposed in this study can be deployed at control centers and in transmission substations to operate power systems in certain configurations and to allow or prevent the operation of overstressed breakers [165]. A tremendous amount of information on circuit breakers can be leveraged by combining manufacturer data, breaker adequacy data and fault history data. Additional information about the topology of the entire system can be retrieved using the communication networks between different relays and between relays and the control center.

Substation reconfiguration strategies can be deployed at the substation level. The data for circuit breaker adequacy can be combined with the fault and interruption history recorded by the relays to form a comprehensive circuit breaker database. In turn, relays can benefit from the comprehensive data set and other knowledge of the power system to implement the substation reconfiguration sequences. Relay coordination inside substations is achieved using the networking capabilities of computer-based relays. Although certain substation reconfiguration sequences may be memorized in advance for certain fault scenarios, the long-term objective is to have substation reconfiguration sequences generated in real time (within a few cycles) as faults occur.

At the control center level, two applications of this study can be deployed. First, a supervising application that oversees the substation reconfiguration process and complements the reconfiguration functionality deployed at individual substations can be integrated in control rooms. Such an application collects and summarizes the status of the topology at each substation in the studied system. Second, the application of circuit breaker adequacy constraints to the economic dispatch problem can be implemented. Generation capacity constraints brought by specific circuit breakers can be reported at the control center and highlighted to provide a global vision of sensitive areas to the operators. Therefore, operators can commit generators depending on desired breaker reliability levels as well as margins between the demand and the total power installed.

With a comprehensive set of circuit breaker data available, comprehensive control and protection schemes can be implemented using the breaker reliability methodology presented in this study. Ultimately, protection schemes and control center applications will become aware of the constraints imposed by the limitations of circuit breaker ratings and integrate these constraints into the real-time operation of power systems.

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VITA

Q. Binh Dam (Vietnamese: *Đàm Quang Bình*) grew up in the southern suburbs of Paris, France. From 1998 to 2000, he attended the prestigious Lycée Louis-le-Grand in Paris for the "Classes Préparatoires," a two-year, non-credit honors program required for admission into French national engineering schools. He received his Engineer's Diploma in Electrical and Computer Engineering in 2003 from the National Polytechnic Institute of Toulouse, France. The same year, upon participation in the Georgia Tech Lorraine graduate program, he obtained a Master's degree in Electrical and Computer Engineering from the Georgia Institute of Technology.

As a doctoral student at the Georgia Institute of Technology, under the supervision of Professor A. P. Sakis Meliopoulos, Binh conducted research on circuit breaker adequacy, protective relaying, and phasor measurement unit testing. He contributed papers in all of these areas and received a paper award at the 62$^{\text{th}}$ annual Georgia Tech Protective Relaying Conference. In addition to research, Binh was a teaching assistant for Electromagnetics in Fall 2003 and Power Systems Protection in Spring 2008. Binh is a member of IEEE and member of the IEEE Power and Energy Society.

Binh has been a graduate representative of the Student Government Association of the Georgia Institute of Technology from 2005 to 2008. He has also been promoting energy and environmental consciousness by serving on the Georgia Tech Earth Day committee, by overseeing improvements to recycling programs in the residence halls, and by promoting fuel economy responsibility.

Binh's greatest passion is music; he has been playing the piano for more than 20 years. He also has more than six years of experience practicing Aikido, a Japanese martial art focused of harmony and resolution of conflicts.